CAN THE U.S. ELECTRIC GRID TAKE ANOTHER HOT SUMMER?

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND RESOURCES

OF THE

COMMITTEE ON GOVERNMENT REFORM

HOUSE OF REPRESENTATIVES

ONE HUNDRED NINTH CONGRESS

SECOND SESSION

JULY 12, 2006

Serial No. 109–229

Printed for the use of the Committee on Government Reform

Available via the World Wide Web: http://www.gpoaccess.gov/congress/index.html
http://www.house.gov/reform

U.S. GOVERNMENT PRINTING OFFICE

34–544 PDF WASHINGTON : 2007

For sale by the Superintendent of Documents, U.S. Government Printing Office
Internet: bookstore.gpo.gov Phone: toll free (866) 512–1800; DC area (202) 512–1800
Fax: (202) 512–2250 Mail: Stop SSOP, Washington, DC 20402–0001

COMMITTEE ON GOVERNMENT REFORM

TOM DAVIS, Virginia, *Chairman*

CHRISTOPHER SHAYS, Connecticut
DAN BURTON, Indiana
ILEANA ROS-LEHTINEN, Florida
JOHN M. MCHUGH, New York
JOHN L. MICA, Florida
GIL GUTKNECHT, Minnesota
MARK E. SOUDER, Indiana
STEVEN C. LATOURETTE, Ohio
TODD RUSSELL PLATTS, Pennsylvania
CHRIS CANNON, Utah
JOHN J. DUNCAN, JR., Tennessee
CANDICE S. MILLER, Michigan
MICHAEL R. TURNER, Ohio
DARRELL E. ISSA, California
JON C. PORTER, Nevada
KENNY MARCHANT, Texas
LYNN A. WESTMORELAND, Georgia
PATRICK T. MCHENRY, North Carolina
CHARLES W. DENT, Pennsylvania
VIRGINIA FOXX, North Carolina
JEAN SCHMIDT, Ohio
BRIAN P. BILBRAY, California

HENRY A. WAXMAN, California
TOM LANTOS, California
MAJOR R. OWENS, New York
EDOLPHUS TOWNS, New York
PAUL E. KANJORSKI, Pennsylvania
CAROLYN B. MALONEY, New York
ELIJAH E. CUMMINGS, Maryland
DENNIS J. KUCINICH, Ohio
DANNY K. DAVIS, Illinois
WM. LACY CLAY, Missouri
DIANE E. WATSON, California
STEPHEN F. LYNCH, Massachusetts
CHRIS VAN HOLLEN, Maryland
LINDA T. SANCHEZ, California
C.A. DUTCH RUPPERSBERGER, Maryland
BRIAN HIGGINS, New York
ELEANOR HOLMES NORTON, District of Columbia

BERNARD SANDERS, Vermont (Independent)

DAVID MARIN, *Staff Director*
LAWRENCE HALLORAN, *Deputy Staff Director*
TERESA AUSTIN, *Chief Clerk*
PHIL BARNETT, *Minority Chief of Staff/Chief Counsel*

SUBCOMMITTEE ON ENERGY AND RESOURCES

DARRELL E. ISSA, California, *Chairman*

LYNN A. WESTMORELAND, Georgia
ILEANA ROS-LEHTINEN, Florida
JOHN M. MCHUGH, New York
PATRICK T. MCHENRY, NORTH CAROLINA
KENNY MARCHANT, Texas

DIANE E. WATSON, California
BRIAN HIGGINS, New York
TOM LANTOS, California
DENNIS J. KUCINICH, Ohio

EX OFFICIO

TOM DAVIS, Virginia
HENRY A. WAXMAN, California

LAWRENCE J. BRADY, *Staff Director*
DAVE SOLAN, *Professional Staff Member*
LORI GAVAGHAN, *Clerk*
SHAUN GARRISON, *Minority Professional Staff Member*

CONTENTS

CAN THE U.S. ELECTRIC GRID TAKE ANOTHER HOT SUMMER?

WEDNESDAY, JULY 12, 2006

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY AND RESOURCES,
COMMITTEE ON GOVERNMENT REFORM,
Washington, DC.

The subcommittee met, pursuant to notice, at 2:08 p.m., in room 2154, Rayburn House Office Building, Hon. Darrell E. Issa (chairman of the subcommittee) presiding.

Present: Representatives Issa, Westmoreland, Bilbray, Higgins and Kucinich.

Staff present: Larry Brady, staff director; Lori Gavaghan, legislative clerk; Tom Alexander, counsel; Dave Solan and Ray Robbins, professional staff members; Joe Thompson, GAO detailee; Shaun Garrison, minority professional staff member; and Cecelia Morton, minority office manager.

Mr. ISSA. Thank you, ladies and gentlemen. I call this meeting to order, a quorum being present.

This is a hearing of the Government Reform Subcommittee on Energy and Resources. I ask unanimous consent that the gentleman from California, Mr. Bilbray, be permitted to participate in this hearing today. Without objection, so ordered.

Good afternoon again. Welcome to the subcommittee.

Today, we will highlight FERC's recently released Summer Energy Market Assessment of 2006, which identified four major geographic areas of potential critical electrical supply. These areas are southern California, my home; Long Island, NY; southwestern Connecticut; and the Ontario, Canada, area, which affects the Great Lakes and clearly has an impact into our country because it is a source for our power.

Each of these areas is particularly vulnerable in the hot summer. They are also at risk to unplanned outages by local generators and disruptions in electricity imports from other regions. Each of the potential U.S. trouble spots were identified, no surprise, in FERC's 2004 and 2005 summer assessments.

The issue is of paramount importance not only because I have constituents in southern California who have previously had the lights go out but because they are important to the economic well-being of the entire Nation.

The potential for rolling blackouts and supply shortages particularly in these regions would have spillover affects and thus greater implications for the Nation's electricity system. Furthermore, supply shortages would have a significant negative impact, especially taking into account the current high price of power.

In addition to hearing today from FERC on its summer assessment, we will hear from regional Independent System Operators [ISOs] which coordinate electrical transmission and oversee wholesale electricity markets in the U.S. trouble spots.

An important question today for our witnesses is: What are you doing to address the summer's challenges—bearing in mind these trouble spots read like a list of the usual suspects from past assessments—and what are you doing in the long term? I'm particularly interested, assuming we squeeze by this summer, what are we doing for the years ahead, assuming a robust and increasing economy?

On our first panel today we are pleased and privileged to have, I believe for the first time by the new chairman, the Honorable Joseph T. Kelliher, chairman, Federal Energy Regulatory Commission.

Our second panel will be represented by ISOs and a municipal from southern California. We will be welcoming Mr. Yakout Mansour, president and CEO of the California ISO; Mr. Mark Lynch, president and CEO of the New York ISO; Mr. Peter Brandien, VP of System Operations at the ISO of New England; and Ms. Phyllis Currie, general manager of Pasadena Water and Power, a member of the ISO and a public utility.

I look forward to these witnesses.

[The prepared statement of Hon. Darrell E. Issa follows:]

COMMITTEE ON GOVERNMENT REFORM
SUBCOMMITTEE ON ENERGY AND RESOURCES

OPENING STATEMENT OF
CHAIRMAN DARRELL ISSA

Oversight Hearing:

"Can the U.S. Electric Grid Take Another Hot Summer?"
(Working Draft)

July 12, 2006

Good afternoon everyone and welcome to our Subcommittee hearing. Today, we will highlight the Federal Energy Regulatory Commission's recently released *Summer Energy Market Assessment 2006*, which identified four major geographic areas with potentially critical electricity supply issues. The areas are: Southern California; Long Island, New York; Southwestern Connecticut; and Ontario, Canada, which affects the US states in the Great Lakes region. Each of these areas is particularly vulnerable to a hot summer and unplanned outages from local generators, as well as, disruptions in electricity imports from other regions. Each of the potential U.S. trouble spots was also identified in FERC's 2004 and 2005 summer assessments.

This issue is of paramount importance not only for my constituents in Southern California, but also for the entire nation.

The potential for rolling blackouts and supply shortages in particular regions would have spillover effects and thus greater implications for the nation's electricity system. Furthermore, supply shortages would have a significant negative economic impact, especially taking into account that prices for power are already high.

In addition to hearing more from FERC on its summer assessment, we will hear from the regional Independent System Operators, which coordinate electricity transmission and oversee wholesale electricity markets in the U.S. trouble spots.

An important question for our witnesses to answer is, "What are you doing to address this summer's challenges?" Bearing in mind the trouble spots read like a list of "usual suspects" from past assessments, another question you must answer is, "What are you doing to avert a crisis in the long-term?"

On the first panel, we are privileged to have here today:

- The Honorable Joseph T. Kelliher, Chairman, Federal Energy Regulatory Commission

On the second panel, we have representatives of ISOs and a municipal utility from Southern California. I welcome:

- Mr. Yakout Mansour, President and CEO, California Independent System Operator
- Mr. Mark S. Lynch, President and CEO, New York Independent System Operator
- Mr. Pete Brandien, VP of System Operations, ISO New England
- Ms. Phyllis Currie, General Manager, Pasadena Water and Power

I look forward to hearing from our witnesses.

COMMITTEE ON GOVERNMENT REFORM

Subcommittee on Energy and Resources

DARRELL ISSA, CHAIRMAN

Oversight Hearing:

"Can the U.S. Electric Grid Take Another Hot Summer?"

July 12, 2006, 2:00pm
Rayburn House Office Building
Room 2154

BRIEFING MEMORANDUM

Summary:

In May, The Federal Energy Regulatory Commission (FERC) released its *Summer Energy Market Assessment 2006*, which identified four major geographic areas with potentially critical supply scarcity issues. The areas are: Southern California; Long Island, New York; Southwest Connecticut Ontario, Canada, which affects the US states in the Great Lakes region. Each of these areas is particularly vulnerable to a hot summer and unplanned outages from local generators or import-related transmission of power from other regions. Each of the potential US trouble spots was also identified in FERC summer assessments in 2004 and 2005.

Additionally, each of these areas is managed by an Independent System Operator (ISO), which is an independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system. ISOs also oversee wholesale or bulk electricity markets and are involved in regional planning activities.

The potential for rolling blackouts and supply shortages in particular regions would have spillover effects and greater implications for the nation's electricity system. Furthermore, supply shortages would have a significant negative economic impact, especially taking into account that prices for power are already high.

This hearing will examine FERC's summer assessment as well as those of the ISOs for

the affected regions. In addition, the hearing will explore the steps FERC and the ISOs are taking to meet the challenges presented this summer and what they are doing to address problems over the long term.

FERC's *Summer Energy Market Assessment 2006*

FERC's *Summer Energy Market Assessment 2006* predicts potential blackouts and high electric bills for Southern California; Long Island, New York; Ontario, Canada, which affects the US states in the Great Lakes region; and Southwest Connecticut. These areas have been of concern for the last several years, demonstrated by the fact that these areas have been in previous summer assessments by FERC. The following sections summarize FERC's assessment and the challenges presented in the four "trouble spot" areas identified.

Southern California

Because of tight reserve margins, Southern California is very vulnerable both to peak demand from periods of heat, and to unplanned outages of generation or transmission capacity needed to maintain imports of power. This area relies on significant amounts of imported power, which will keep transmission lines in southern California heavily loaded much of the time. For example, the California Independent System Operator (CAISO) expects typical peak demand in Southern California during the summer to be about 27,300 MW with peaks under high load scenarios of more than 29,500 MW. Local generation, adjusting for likely outages, totals a little less than 20,000 MW. At the peak, the CAISO expects 10,100 MW to be imported – or fully one-third of Southern California's supply.

Consequently, FERC's Summer Assessment, which is consistent with the North American Electric Reliability Council (NERC) assessment, is that if loads or unexpected outages are high, the CAISO will call on more imports to maintain sufficient operating reserve margins. However, if Southern California has sustained periods of high temperatures coupled with the unexpected loss of local generation or transmission, the CAISO may need to shed load through rolling blackouts.

The California Public Utilities Commission mandated resource adequacy requirements for all Load Serving Entities within their jurisdiction. Load Serving Entities, which provide electric service to end-users and wholesale customers, are required to procure energy resources to meet their 90 percent of summer peak demand one year in advance. In addition, Load Serving Entities are now required to procure energy resources equal to at least 115 percent of forecasted monthly peak load. Thus, extending forward contracting reduces spot price effects on customers.

Southwestern Connecticut

Southwestern Connecticut will not have enough local generation and import transmission capacity to meet expected demand and reliability requirements. Transmission capacity for imports now operates at its limit and transmission capacity with Southwest Connecticut is insufficient to support local generation. In addition, no significant generation or transmission capacity has been added since 2004; current transmission upgrades will not be completed until 2009.

Southwestern Connecticut is very vulnerable to extended periods of high temperatures and unplanned outages of local generation or imported transmission. Therefore, the lack of investment in basic infrastructure within the regions creates probable conditions that southwestern Connecticut will experience expensive electric prices this summer, but not rolling blackouts.

Long Island/ New York City

New York City's recent investment in critical generation infrastructure appears to have relieved some reliability concerns. However, the power plants are gas-fired and due to high natural gas prices, the market price for electricity is expected to remain relatively expensive in the city, though reserves appear adequate. However, Long Island has supply-demand balances that remain very tight.

Long Island is vulnerable to extended periods of heat and unplanned outages. Therefore, when supply is tight, such as during an extended period of heat, prices for electricity will be extremely high. In addition, the New York ISO's scarcity pricing program, implemented in 2003, is likely to continue to generate high prices at those times when tight markets means reserves are being used for energy.

Ontario, Canada

Ontario relies on transmission imports from New York, Michigan, and the Province of Quebec to meet its demand. Generation and transmission capacity have increased, slightly, but this has not made up for the increase in demand. Therefore, Ontario, like most of North America, is vulnerable to extended periods of high temperature and unexpected outages. Further, Ontario is dependent on imports or power, and it could be subject to import restrictions if there is a heat-wave in the northeastern United States.

Given its geographical location, if Ontario has a need for emergency energy it could have a negative effect on the supply in New York and the Midwest, thus increasing the price to consumers in those regions. In addition, last summer Ontario disrupted imports frequently, causing a variety of commercial problems. Ontario's Independent Electricity System Operator has implemented a day-ahead commitment process which may take care of this issue for the upcoming summer.

Common Structural Problems

These regions each suffer from structural, not just seasonal, energy problems. The regions demonstrate the difficulties that the nation is experiencing in meeting its electricity reliability needs. Common challenges include: funding, siting and construction of new generation and transmission capacity; regulatory uncertainty; and volatile fuel supplies and prices.

The present transmission system was developed to fit the regulatory framework established in the 1920 Federal Power Act, under which utilities served local customers in a monopoly service territory. The transmission system was not designed to handle large power transfers between utilities and regions. Enactment of the Energy Policy Act of 1992 created tension between the existing transmission system and the Act's new regulatory mandates: the new competitive generation market encouraged wholesale, interstate power transfers across an older grid system that was designed to protect local reliability, not bulk power transfers.

Demand Outstrips Transmission Capacity

According to the Congressional Research Service (CRS) report, *Electric Reliability: Options for Electric Transmission Infrastructure Improvements,* electricity demand has been growing at 2% to 3% per year, but additions to the transmission system have been growing by only 0.7% per year. This has resulted in transmission lines that are congested in several regions of United States. Therefore, certain regions of the United States have very tight reserve margins and are very vulnerable both to high peak demand from periods of heat, and to unplanned outages of generation or transmission capacity needed to maintain imports.

Several factors have contributed to the lack of new transmission capacity. First, there is general consensus that siting new lines is difficult, needing approval of all states in which the transmission line will be located. However, the Energy Policy Act of 2005 mandates that the Department of Energy produce a list of "critical corridors" for transmission infrastructure by August 2006 and DOE is on track to meet this deadline. Furthermore, these corridors would have "fast track" siting approval process.

Second, some have argued that the current pricing mechanism for transmission is a deterrent for investors. For example, transmission development remains an area that competes for investment with distribution investments, which, regulated at the state level, often carry a higher rate of return than those allowed at the interstate level by the FERC. Consequently, transmission projects are often terminated. Third, many contend that regulatory uncertainty has added a level of risk that investors are unwilling to assume.

Regulatory Uncertainty is a Factor in Lack of Capacity

The Energy Policy Act of 1992 introduced competition to wholesale electric transactions without a comprehensive plan to address reliability issues and the development of efficient wholesale markets. Therefore, approximately half of the states have passed legislation or had regulatory orders to introduce retail competition, each with its own set of rules for utilities to follow.[1] In addition, the blackouts of 2003 in the Northeast, Midwest, and Canada have highlighted the need for infrastructure improvements and greater standardization of operating rules. Many observers predict that until the electric power industry reaches a new equilibrium with more regulatory certainty, investment in transmission infrastructure and technology will continue to be inadequate.

Impact on Fuel supplies

Experts have predicted another active hurricane season, which could periodically curtail Gulf of Mexico production of natural gas and oil. Although fuel deliverability problems are possible for limited periods of time (due to hurricanes, etc.), the larger immediate impact will likely be economic (e.g., higher electricity prices). However, the few new power plants that are built in the United States are gas-fired plants that are vulnerable to rapid increases in natural gas prices due to severe weather or scarcity of supply. According to NERC's summer assessment, natural gas-fired power plants will comprise more than 8,000 MW of the approximately 11,800 MW of generation being added this summer across the United States.

ISSUES TO BE ADDRESSED AT THE HEARING:

- FERC's summer assessment and forecast by the regional ISOs for the affected regions;
- The steps FERC and the ISOs are taking to meet the challenges presented this summer;
- Actions taken by FERC and the ISO's to address supply and transmission problems over the long-term.

[1] Twenty-two states and the District of Columbia have plans to allow for retail choice for electricity. According to the Energy Information Administration, in 1996, 10 percent of generating capacity was owned non-utility generators. In addition, to encourage competition, Maine and New Hampshire have required utilities to fully divest of either generation or transmission assets and California and Rhode Island have partial divestiture requirements.

Witnesses:

- The Honorable Joseph T. Kelliher, Chairman, Federal Energy Regulatory Commission
- Mr. Yakout Mansour, President and CEO, California Independent System Operator
- Mr. Mark S. Lynch, President and CEO, New York Independent System Operator
- Mr. Pete Brandien, VP of System Operations, ISO New England
- Ms. Phyllis Currie, General Manager, Pasadena Water and Power

STAFF CONTACT

Larry Brady, Staff Director
Subcommittee on Energy and Resources
B-349C Rayburn House Office Building
202.225.6427 / 202.225.2392 fax

Mr. ISSA. I ask unanimous consent that the briefing memo prepared by the subcommittee and staff be inserted into the record as well as all other relevant materials.

I now yield to the ranking member, the gentleman from New York, for his opening statement.

Mr. HIGGINS. Thank you, Mr. Chairman.

I don't have an opening statement, but on behalf of ranking member Diane Watson I would ask that her statement be submitted into the record.

Mr. ISSA. Without objection, so ordered.

Mr. HIGGINS. I want to hear the testimony of the expert panelists.

Mr. ISSA. Mr. Kucinich, would you have an opening remark?

Mr. KUCINICH. I do, thank you, Mr. Chairman.

Today, the Federal Energy Regulatory Commission sits before us with the 2006 Summer Energy Market Assessment. This Assessment outlines four geographic areas that may be unable to deal with the surge in electricity demand this summer. Blackouts are possible in those areas.

I want to thank FERC for identifying these areas before we set into the hottest days of summer. But I want to point out that this list is substantially similar to the lists of past years. I hope that FERC will explain to the committee today why these areas continue to reappear on the list, year after year.

I would also like to note for the record that in the 2003 Summer Energy Market Assessment, FERC failed to identify Ohio as an area of concern. Shortly thereafter, in August 2003, the United States suffered its largest blackout ever. This blackout began in Ohio, and it spread across much of the northeastern United States and Canada. I think most people remember it. If we are to believe FERC's prediction for 2006, we need to be confident that the Federal Energy Regulatory Commission overcame its past shortcomings that contributed to the 2003 blackout.

Let me remind the subcommittee that deregulation of this energy market was and still is creating reliability problems. First Energy, like many power companies, was driven by a motivation to put profit above the public interest. This culture has led to a lack of maintenance and deterioration of their infrastructure. These factors played a key role in the 2003 blackout that caused 50 million people to lose power.

The U.S.-Canada Power System Outage Task Force Interim Report found that First Energy bears significant responsibility for the largest blackout in U.S. history. Essentially, First Energy, in its bid to maximize profit, caused an estimated $6 billion in economic losses. Reliability is the cornerstone of responsible electricity production, and in a deregulated market the regulator has to step up and ensure reliability is not sacrificed for greater profits. I hope the Federal Energy Regulatory Commission understands this.

The excessive electricity rates paid by the American people should come at least with a guarantee of reliable service. Instead, deregulation has driven prices higher and made our electricity system more visible to disruption. We are paying more for worse service.

Thank you very much, Mr. Chairman, for holding this hearing; and I look forward to the testimony of the witnesses.

Mr. ISSA. Thank you, Mr. Kucinich.

For all Members, there will be 5 legislative days in which to submit their opening remarks.

With that, I would like to ask not only Chairman Kelliher but all the other witnesses to please rise and take the oath according to our committee's rules. Also, anyone who is going to provide access and speak on behalf, please raise your right hand.

[Witnesses sworn.]

Mr. ISSA. The record will show that everyone answered in the affirmative, including a very darling young child.

Mr. Chairman, we normally ask you to stay within 5 minutes. By unanimous consent, your entire testimony will be in the record, so you are free go off of that if you dare. Thank you.

STATEMENT OF JOSEPH T. KELLIHER, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION

Mr. KELLIHER. Thank you, Mr. Chairman.

Mr. Chairman, members of the subcommittee, thank you for this opportunity to appear before you to discuss the Commission's Summer Energy Market Assessment and the measures we have taken to assure adequate electricity supply and enhance the interstate electric transmission grid. The Energy Policy Act of 2005 gave the commission important new regulatory tools to address both market and reliability issues, and I welcome this chance to review current market issues and to report to you on how we are using the new authorities you gave us just last year.

Mr. Chairman, first of all, let me start by commending you for holding this hearing. Six years ago, an electricity crisis began in California. It quickly extended to the rest of the West and endured for a year. The reason the California crisis expanded and became the western power crisis is that California is not a distinct and separate electricity market. It is part of a broader western electricity market, and I think it is important. That event demonstrates the nature of wholesale power markets in the United States. Power markets are not neatly defined by State boundaries, but we also don't have a national electricity market. Instead, we have a series of regional markets, and there is significant differences among those regions.

Now, wholesale power markets are also international. The United States is fully interconnected with Canada and with part of Mexico. So wholesale power markets are actually in some instances both regional and international. I think that is one reason the Commission looked at the Ontario market this year, because it clearly has effects in the United States; and I go through that introduction really to emphasize that problems in southern California do not remain within southern California and they can extend and affect other markets. So I want to commend you for the focus of this hearing today.

Now the Commission staff prepares an assessment of energy market conditions before each summer electricity cooling season and each winter natural gas heating season. These reports highlight major changes from years before and areas of potential concern for the upcoming season; and, overall, there has been improvement over the past year.

The Assessment noted four geographic areas in North America that could face problems this summer: southern California, Long Island, southwest Connecticut and Ontario, with implications for adjoining markets in Michigan and New York. Now in all four areas supplies appear to be adequate to meet normal demands on the system, but all four regions could be at risk if the demand is high or key parts of the generation or transmission system have unplanned outages. Under these conditions, prices could be high and some load may need to be shed.

Now each of these areas has already been tested by some periods of early summer heat; and, so far, there have been no major problems. In most regions, however, July and August are the times of greatest vulnerability to sustained high heat, so we are not out of the woods yet. Moreover, looking beyond the summer, all four of these areas that were the focus of the Commission's Assessment remain at greater risk of electricity supplies tightened in future years.

Now turning to the four regions identified in the Assessment, southern California faces another summer of tight supply in an area of fast-growing demand. The region depends very heavily on imports from northern California, from the Pacific Northwest and the Southwest, particularly at peak. In their high-load scenario, southern California needs to import 10,000 megawatts, fully a third of its supply. That is a much higher dependence on imports than we see in most other parts of the country. Since last year, transmission upgrades have helped import capability somewhat, but net generation growth in southern California barely covered load growth.

Now, southwest Connecticut in the Northeast, southwest Connecticut again faces a very tight balance between supply and demand. Combined local generation and import capability are not sufficient to meet expected demand and reliability requirements. Transmission capacity for imports now operates at or near its limit, while transmission capacity within the region cannot fully support local generation or the addition of new generation.

The region had not added significant generation or transmission capacity since 2004. While transmission upgrades are under way, they will not be complete until late 2009; and until those upgrades are completed, the infrastructure in southwest Connecticut remains very fragile.

Now New York City and Long Island pose longstanding challenges for the electric system. The Assessment noted key improvements in New York City as recent generation investments begin to relieve some reliability concerns. But on Long Island, however, the balance of supply and demand remains tight. Imports from upstate New York and New England are still crucial for Long Island, and the area remains exposed to the risks of heat and unplanned generation and transmission outages.

During last 2 weeks, two of the four major transmission lines into New York City from upstate New York have failed. The loss of these two lines means that New York City as well as Long Island will be tested during any periods of sustained hot weather this summer.

Now, finally, the Assessment touched on the Canadian province of Ontario, which imports power from adjacent U.S. electricity markets in New York and the Midwest as well as the province of Quebec. The Assessment noted the North American Electric Reliability Council's view that Ontario has already lost some of its tight capacity margin since last summer, and our concern is the effects that Ontario demand and the operation of the Ontario market may have the U.S. markets. As indicated earlier, wholesale power markets can be both regional and international, and this is certainly one case of that.

Part of the problem last summer related to Ontario market rules, and I want to praise Ontario regulators. Since last summer, they have changed those rules and adopted day-ahead scheduling earlier this summer, so I think they should be commended for that action.

The problems in the areas studied in the Seasonal Assessment have certain common features. At its most basic level, it is clear that adequate infrastructure is necessary in order to meet demand. Infrastructure is both generation and transmission, the ability to generate electricity supply and the ability to transmit it to where it is needed. It is absolutely necessary that the relationship between adequate infrastructure and prices and reliability be understood and be appreciated. To the extent that infrastructure is inadequate, prices will be higher and reliability will be undermined. It is the inevitable consequence.

Now the question is how to ensure there is enough transmission investment to deliver power to the areas that need it and enough generation to be able to meet demand, especially in highly populated load pockets. And the question is also how do we assure reliability in the bulk power system.

Now we are acting in these areas. One of the Energy Policy Act's major goals is to strengthen the U.S. energy infrastructure, especially the transmission grid. And transmission underinvestment is a national problem. The United States has had a sustained period of underinvestment in the transmission grid that goes back to the 1970's. If you look at the transmission grid, the expansion of the transmission grid last year in terms of circuit miles was 0.5 percent, which is pretty close to zero.

Now recognizing that is a national problem, we are developing a national solution. We have issued proposed transmission pricing rules to spur greater investment in transmission, and we are moving to finalize those rules in the near future.

Now in passing and enacting the Energy Policy Act, Congress determined that some Federal transmission siting authority was needed to lower barriers to adequate investment in the transmission grid. The Commission and the Department of Energy have been working very closely over the past year to implement the transmission siting provisions in the new law, and last month the Commission issued proposed rules to implement the Federal transition siting provisions.

The Commission has also been acting to ensure resource adequacy or adequate electricity supply. This is a complicated area—as you can see from that protest over there—but it is a complicated area in large part because the Federal and State jurisdiction is imperfect in this area. Neither Federal nor State regulators have perfect jurisdiction to assure resource adequacy. That means that we must collaborate and work closely with State regulators and, to the greatest extent possible, since electricity markets are regional in nature, to develop regional solutions to regional problems.

I'd like to highlight for a moment a recent settlement that we approved that would assure resource adequacy in New England. I think it is useful to spend a minute or a part of a minute on this process to show——

Mr. ISSA. Without objection, the gentleman will have another minute.

Mr. KELLIHER. Thank you—on now necessary and difficult it is to address regional resource adequacy issues.

As the Summer Assessment noted, part of New England faces the prospect of electricity supply problems, if not this summer but very soon. Demand for electricity in this region has been growing and growing quite fast, and supply is not increasing to meet demand.

Last year, the New England region as a whole added a total of 11 megawatts in new generation and new electricity supply—11 megawatts—while peak demand rose by 2,700 megawatts. That is exactly the kind of trend we saw in California leading up to the California electricity crisis, a sustained period of a number of years where demand far outstripped supply.

Now the New England region faces the real prospect of supply shortages and high prices in the near future. ISO New England proposed a locational installed capacity plan, or LICAP, to address this resource adequacy problem. This proposal generated considerable controversy and was an area of interest to members and senators from the region, and the Commission urged the parties to engage in settlement discussions around an alternative to the LICAP proposal. We authorized settlement discussions and appointed a settlement judge; and I am happy to report that, in the end, there was a very significant settlement. Out of 115 parties, 108 settled. The region developed a regional solution to this problem, and we ended up adopting the regional solution.

Finally on electric reliability, the Commission has acted very quickly to implement the reliability provisions of the Energy Policy Act. We have issued rules to govern the certification of the electric reliability organization, and we're moving ahead to consider and ultimately adopt enforceable mandatory reliability standards and to ensure that we have a very strong regime of enforcement of reliability standards.

So we're taking actions to address, as you highlighted in your opening statement, these problems in the long term. So thank you for your attention.

Mr. ISSA. Thank you, Mr. Chairman.

[The prepared statement of Mr. Kelliher follows:]

July 12, 2006

Summary of Testimony of the Honorable Joseph T. Kelliher
Chairman, Federal Energy Regulatory Commission
Before the Committee on Government Reform
Subcommittee on Energy and Resources
United States House of Representatives
July 12, 2006

The Commission Staff's Summer Assessment reported improved supplies for natural gas and hydroelectric power production. Electric generators have been building coal stockpiles after starting the year at low levels. It noted four regions of possible concern for the summer of 2006: Southern California, Southwest Connecticut, New York City and Long Island, and the areas adjoining Ontario in Canada. In each case, unusually high levels of temperature and unplanned outages could stress the electric grid. Recently, transmission line outages into New York City have at least partially offset the value of new generation added since last year.

The Commission is working hard to ensure affordable, reliable electric power both in the areas of immediate concern identified in the summer assessment and more generally around the country. For electric transmission, we are poised to use a key provision of the Energy Policy Act of 2005 (EPAct) to implement incentive pricing for transmission. We have worked closely with the Department of Energy to implement the EPAct provision allowing federal siting of electric transmission in national interest transmission corridors that the Department of Energy may designate. We are ready to act on construction permits for transmission lines within designated corridors.

To ensure resource adequacy, we are working with regional transmission operators around the country to create mechanisms like capacity markets, even when these measures may become controversial. We recently approved a Forward Capacity Market for New England for this purpose. It addresses one of the most pressing regional needs in the country.

Finally, we are moving rapidly to implement the reliability provisions of EPAct. We issued rules to certify an Electric Reliability Organization (ERO) last winter. I expect final action on certifying an ERO very soon. We are now also actively preparing to act on reliability standards when they are submitted.

July 12, 2006

Testimony of the Honorable Joseph T. Kelliher
Chairman, Federal Energy Regulatory Commission
Before the Committee on Government Reform
Subcommittee on Energy and Resources
United States House of Representatives
July 12, 2006

Mr. Chairman and Members of the Committee:

Thank you for this opportunity to appear before you to discuss the Commission's Summer Energy Market Assessment and the measures we have taken to facilitate resource adequacy and to enhance the interstate electric transmission grid. The Energy Policy Act of 2005 (EPAct) gave us important new tools to address both market and reliability issues in each region. I welcome this chance to review current market issues and to report to you on how we are using the new authorities you gave us.

I. The Summer Assessment

I will begin with the Commission's Summer Assessment. The Commission's staff prepares an assessment of energy market conditions before each summer's electric cooling season and winter natural gas heating season. These reports highlight major changes from the year before and areas of potential concern for the upcoming season.

The staff presented the Summer 2006 Assessment at our Commission Meeting held on May 18. The Assessment was generally reassuring.

A. Hydroelectric and Fuel Supply

Hydroelectric conditions in the West are far better this year than last, providing a margin of safety throughout the region, at least for the beginning of the summer.

Natural gas prices have fallen compared to oil. In Florida and New York, regions where fuel-switching is important, we have seen significant levels of switching from oil to natural gas. As a result, more gas is being used for generation nationally, but at prices 15 percent lower on average around the country than they were a year ago before the hurricanes.

Coal stockpiles early in the year, on the other hand, were at relatively low levels compared with most recent years. Low stockpiles were especially prevalent in regions served by Western Powder River Basin coal. I am pleased to report to you that on June 15, the Commission held a public discussion on rail deliveries of Western coal and possible effects on reliability. Representative of both the electric utility industry and the railroad industry provided their perspectives on the issues. Good, timely statistics about coal deliveries are hard to come by, but our staff has tracked what appears to be some improvement recently.

The Assessment noted four geographic areas in North America that could face problems this summer: Southern California, Long Island, Southwest Connecticut, and Ontario with implications for adjoining markets in Michigan and New York. In all four areas, supplies appear to be adequate to meet normal demands on the system. But all four regions could be at some risk if loads are high or key parts of the generation and transmission system have unplanned outages. Under these conditions, prices could be high and some load might need to be shed.

Before I turn to the four regions individually, I want to note that each has already been tested by some periods of early summer heat. So far, there have been no major problems in any of the four regions. Still, this is not the time for complacency. In most regions, July and August are the times of greatest vulnerability to sustained high heat. Moreover, looking beyond this summer, all four regions remain at greater risk if fuel supplies tighten in future years.

B. Southern California

Turning to the four regions identified in the Assessment, Southern California faces another summer of a tight supply in an area of fast growing demand. The region depends heavily on imports from northern California, the Pacific Northwest and the Southwest, particularly at peak. Under high load scenarios, Southern California needs to import 10,000 megawatts (MW), fully a third of its load. Since last year, transmission upgrades may have helped import capability somewhat, but net generation growth barely covered load growth.

If loads or unplanned outages are high, the California Independent System Operator (ISO) will call on interruptible demand and demand response to maintain adequate operating reserve margins. Under extreme – and fairly unlikely – conditions, the ISO might again need to shed load through rolling blackouts in Southern California.

Southern California faced its first test for this summer when hot weather covered the whole West for several days two weeks ago. No major problems emerged during this period. That is good news. But it is important to remember that August and September are likely to bring greater challenges, as hydropower reserves are drawn down and temperatures rise further.

C. Southwest Connecticut

In the Northeast, Southwest Connecticut again faces a very tight balance between supply and demand. Combined local generation and import capacity are not sufficient to meet both expected demand and reliability requirements. Transmission capacity for imports now operates at or near its limit while transmission capacity within the region cannot fully support local generation. The region has not added significant generation or transmission capacity since 2004. Under current plans, there will be some improvement in transmission inside the region later this year. Transmission upgrades for imports will not be completed until late 2009.

As in Southern California, the most important threats to electricity markets in Southwest Connecticut come from extended periods of summer heat and from unplanned outages. Widespread heat in the northeastern United States could limit imports into Southwest Connecticut also. Overall, the fragility of the infrastructure into and within the region makes summer problems possible and maybe even likely.

D. New York City and Long Island

New York City and Long Island pose long-standing challenges for the electric system. The Assessment noted key improvements in New York City, as recent generation investments began to relieve some reliability concerns.

On Long Island, however, the balance of supply and demand remains tight. Imports from upstate New York and New England are still crucial for Long Island and the area remained exposed to the risks of heat and of unplanned generation and transmission outages.

During the last two weeks, two of four major transmission lines into New York City from upstate New York have failed. They will be for some time. Our Division of Reliability is consulting closely with the affected transmission owner to ensure that the outages have no reliability effects. Nonetheless, the loss of these two lines means that New York City as well as Long Island will be tested during any periods of sustained hot weather.

E. Ontario

Finally, the Assessment touched upon the Canadian Province of Ontario, which imports power from adjacent U.S. electric markets in New York and Michigan, as well as the Province of Quebec. The Assessment noted the North American Electric Reliability Council's view that Ontario has lost some of its already-tight capacity margin since last summer.

Our concern is the effects that Ontario demand may have on U.S. markets. Demands for emergency energy could make balancing supply and demand in New York and in the Midwest more difficult and more costly. Ripple effects could be felt in PJM and New England as well.

II. Commission Actions

All four of the areas identified as concerns in the Seasonal Assessment involve two key problems: how to ensure that there is enough transmission investment to deliver power to the areas that need it and how to ensure that there is enough generation available to keep the lights on, especially in highly populated load pockets. With EPAct, Congress gave the Commission new tools to help address these concerns among others, including reliability. I am pleased to report to you the progress the Commission has made in using those new tools.

A. Transmission Investment

Let me start with transmission. Our nation's transmission system has suffered from underinvestment for years. In 2004, the interstate transmission system expanded by a total of 0.6 percent in circuit miles. Transmission congestion has risen steadily since 1998.

One of EPAct's major goals is to strengthen our energy infrastructure, especially the transmission grid. Transmission underinvestment is a national problem. We need a national solution. Using important provisions of EPAct, the Commission is addressing two key impediments to transmission investment: the failure of transmission rates to give a strong enough incentive for investment and the difficulty in siting new lines.

Transmission investment will not return unless the rates companies are allowed to charge for transmission give them a strong enough incentive to invest in new transmission. Accordingly, we issued proposed rules on November 17, 2005, to implement incentive pricing for transmission under EPAct. The goal of the proposed rules is clear: secure greater investment in the transmission grid. A stronger transmission grid will increase electric system reliability and promote greater wholesale competition.

Our proposed rules encourage investment in transmission in all regions, by both vertically integrated utilities and transmission companies. Transmission companies are a proven vehicle for transmission investment. Internal analysis at the Commission shows that transmission companies are investing five times as much as prior owners. We want to reinforce that success. The Commission has been working on transmission pricing reform for nearly three years. We are hoping to issue a final rule very soon.

B. Transmission Siting

Siting is the second major barrier to transmission investment. In enacting EPAct, Congress recognized that a robust transmission grid is important to both assure reliability and support competitive markets and that some federal transmission siting authority was needed to lower barriers to major transmission projects.

EPAct, therefore, authorizes siting of interstate electric transmission facilities in "national interest electric transmission corridors" designated by the Department of Energy. The Department is working on its congestion study, which is expected to be issued in early August. At some point after August, the Department may begin designating these corridors.

I want to congratulate the Department of Energy for its work on the congestion study and to express my confidence in its ability to designate transmission corridors in a timely manner, consistent with the statute. The Commission and the Department of Energy have been working closely and productively. In particular, I want to commend it for the recent delegation order, which delegated to the Commission lead agency status once a permit application is filed.

We will be ready to act on construction permits. Last month, even as the Department of Energy completes its congestion study, the Commission issued proposed rules to implement the transmission siting provisions of EPAct. These rules will govern the issuance of construction permits by the Commission for projects that meet the statutory criteria. My intent is to have the Commission's final transmission siting rules in place by the time the Department of Energy may begin designating transmission corridors.

In talking about transmission siting, I want to emphasize two points. First, EPAct gives the Commission a carefully limited role that supplements state authorities rather than supplanting them. Second, the Commission is well qualified to do the work of siting new transmission facilities when the law calls upon it to do so.

The federal transmission siting provisions differ profoundly from those that govern natural gas in that they do not preempt the states and do not provide for exclusive federal siting. In fact, I expect that states will continue to site most transmission projects under state law.

We are also well-equipped to handle those projects that we do site. In those cases, the role we are assigned is familiar to us from our work in siting gas pipelines, something we have been doing for decades. In the past five years alone, we have sited more than 8,000 miles of pipelines. For natural gas pipelines, it now takes us an average of only 11 months to go from a filing through the full comprehensive review needed to approve construction. I have no doubt we will be able to site transmission projects as efficiently and fairly as we site natural gas pipelines, when we are called upon to do so.

C. Electric Generation Adequacy

Transmission reform addresses half of the issues raised for load pockets in the

Summer Assessment. Ensuring generation adequacy is the other half. The Commission and regional transmission operators around the country have recognized the issue and have worked hard to create mechanisms, such as capacity markets, to address them. I would like to focus on a settlement we recently approved in New England to address the issue for a region with a particularly pressing version of the problem. The process shows both how necessary and how difficult it is to address regional resource adequacy issues.

As the Summer Assessment noted, parts of New England face the prospect of an electricity supply problem, if not this summer, then very soon. Demand for electricity in the region is growing. Supply is not increasing to meet demand. Last year New England added 11 MW of new generation while its peak demand rose by 2,700 MW. The region faces the prospect of real supply shortages and very high prices.

We have seen a consensus in New England for some time around these basic facts, though there are disagreements about how soon supply shortages and high prices might be realized.

ISO New England proposed a location installed capacity proposal (LICAP) to address the problem. This proposal generated considerable controversy, largely because resource adequacy is not cheap. Many in the region felt they had not had the opportunity to develop a workable alternative. In response, we urged the parties to engage in settlement discussions around an alternative to the LICAP proposal. We authorized settlement discussions and appointed a settlement judge.

These discussions were productive, and resulted in a settlement that we approved this spring that establishes a new Forward Capacity Market for New England.

The great majority of the parties settled. They realized that it was better for the region to propose a regional solution to this serious problem facing New England. They negotiated in good faith on a series of difficult issues. They acted responsibly. They also trusted that the Commission would give the views of the region appropriate deference. I want to commend the settling parties for working collaboratively to reach this settlement.

Despite the lack of unanimity, we found that the settlement was just and reasonable, and that the newly established Forward Capacity Market will serve to assure adequate electricity supply and just and reasonable wholesale power prices in New England.

Our decision remains controversial – some in the region have criticized it. Resource adequacy decisions are never easy. But this decision was necessary. In the end, I would prefer to be criticized for acting to prevent a crisis, a crisis New England knows is coming, than for failing to be proactive.

D. Electric Reliability

I will end by noting that the matters I have spoken of today are only a part of the Commission's response to Congress's intent in enacting EPAct. Most importantly, we have acted swiftly to implement the reliability provisions of the statute.

EPAct requires the Commission to issue rules to certify an Electric Reliability Organization (ERO), establish North American and regional reliability standards, authorize delegation of enforcement responsibility from the ERO to regional entities, and oversee the enforcement of mandatory reliability standards.

We issued proposed rules only three weeks after EPAct was signed into law. Parties filed roughly 1,700 pages of comments on the proposed rule. We reviewed the comments thoroughly, and they helped shape the final rule, which we issued early last winter.

The final rule is faithful to the law. EPAct gave the Commission the duty of assuring the reliability of the bulk power system. We will exercise that duty by certifying an ERO, carefully reviewing proposed reliability standards, approving standards that provide for reliable operation of the bulk power system, remanding those that do not, and working to improve reliability standards over time. We will review proposed reliability standards to assure that they not only have technical support but also are written to be enforceable against "all users, owners, and operators of the bulk power system," as required by law.

I am committed to faithfully executing the EPAct as Congress intended, including appropriate regional differences in reliability standards. The law does not provide for absolute uniformity in reliability standards. Under EPAct, regional entities will propose regional standards or variances to the ERO, which can then propose to the Commission those regional standards that it has approved. I take this provision seriously. Congress would not have provided for consideration of regional standards or variances if it had intended a "one size fits all" approach.

With the Final Rule in place, we are now moving forward expeditiously with certifying the ERO. I expect final action on this very soon.

Meanwhile, we have improved our ability to discharge our duties once an ERO is certified and reliability standards established. Last fall, I directed Commission staff to hold a series of technical conferences with industry and stakeholders to review current North American and regional reliability standards, including procedures for establishing, approving, and enforcing electric reliability standards. As part of this effort, Commission staff released a report entitled "Staff Preliminary Assessment of the North American Electric Reliability Council's Proposed Mandatory Reliability Standards" on May 11th of this year.

Last week, the Commission itself held a technical conference to hear reaction to the Staff's report, *Assessment of Reliability Standards*. Not surprisingly, given the importance of the issue, all of the Commissioners attended and played an active role in the discussion. These proceedings will help establish a record that will assist the Commission to issue a Notice of Proposed Rulemaking this fall to act on each of the reliability standards that have been submitted.

In conclusion, the Commission is working hard to ensure reliable, affordable electric power for Americans, both in the areas of immediate concern identified in our summer assessment and more generally around the country. Thank you again for giving me this opportunity to speak, and I will be happy to answer any questions you may have.

Mr. ISSA. I'm going to waive my opening round of questions so that we can get to each of the Members here because of the likelihood that some of them will have to go in and out.

Suffice to say only one thing, which is we have had discussions about how to deal with pump storage and how to price it as advanced transmission; and I recognize that it is a process question, in addition to a pricing question. I also recognize that there are current matters you won't be able to speak to. What I would like to do is give you more time throughout this, and if there is time remaining we will talk on the record about it. Then, if there is not, I would like to submit for the record so that we can have an in-depth discussion of how we are going to progress to promoting this advanced transmission system in every place appropriate around the country. Is that agreeable?

Mr. KELLIHER. Yes, sir.

Mr. ISSA. I thought it would be. Thank you.

With that, vice chairman, Mr. Westmoreland, please start the opening round of questions.

Mr. WESTMORELAND. Thank you, Chairman Issa.

Mr. Chairman, thank you for being here.

Mr. KELLIHER. Thank you.

Mr. WESTMORELAND. Some people have stated in the not-so-distant future reserve margins in certain areas will be at a critical level. I know that transmission has been cited as a solution to this problem, but I feel there needs to be greater emphasis placed on increasing our total energy supplies. What do you see being done to increase new generation?

Mr. KELLIHER. Well, there have been different approaches taken in different regions. One fact that isn't really commonly understood is that the United States, over the past 10 years, have we added electricity supplies? How have we met demands for the past 10 years? Most of that electricity supply over that period has been built by independent power producers. Something like 74 percent of the electricity supply built over that year has been built my non-utilities.

That trend has changed recently. Right now, if you look at most power plants under construction, I believe the majorities right now are being built by utilities, vertically integrated utilities. The United States has met electricity supply in different ways over time. If you were to go back 40 years, how did we build electricity? It was built completely by vertically integrated companies without exception.

In the 1980's, it started being built largely by independent power producers backed by long-term purchase contracts signed by the utility as the buyer and then resold to retail consumers. Five years ago, it was built by nonutilities who were building completely at risk, building multibillion dollar facilities without any contract to sell any of the output. Now that means of building power plants, perhaps that one is not going to be tried again. The risk ended up being much higher than I think the generators anticipated.

Now we are in a period where the balance has shifted back to the utilities building. The question really is, is that a temporary shift? I think probably the right answer is we have different kinds of wholesale power markets. In some wholesale power markets, there is not much left of vertical integration. For example, New England. In New England, by virtue of State action, not FERC action or Federal action, most generation was divested by the utilities. So, in New England, the vast majority of supply is met by independent power producers, and I think it would be very difficult to undo that.

But in other regions of the country vertical integration remains the norm. So I think, probably the correct answer, there is very significant differences among the wholesale power markets in this country. In one region, the solution to meeting supply needs would probably be the independent power producer and in another it might be the vertically integrated incumbent utilities. In others, it will probably be both under some State competitive bidding process. If the utility ends up being the low bidder, perhaps it is perfectly reasonable for them to be the builder, but they may not be.

Mr. WESTMORELAND. Thank you.

One followup question, if I could, Mr. Chairman.

The FERC recent study explained that, in areas of this country, who are in danger of potentially critical supply. Who is responsible for addressing reliability? I know you mentioned the reliability factor versus the cost and the transmission. Is it FERC's job to address the reliability? Is it a State issue? Is it a regional issue? And should it be passed along to that ratepayer such as—I live in Georgia, and we have a great power company there, but should that increase of somebody else's reliability service be passed on to that ratepayer?

Mr. KELLIHER. Well, there are different senses of reliability. In terms of reliability, if you mean in the Energy Policy Act of 2005 sense, the reliability of the bulk power system, those we will set standards at FERC, and those standards will assure reliability of the bulk power system, and the cost of those standards will be recovered and be passed through.

If you are talking about reliability in a broader sense in terms of supply reliability, that's the area that I pointed out it was very complicated, where State and Federal jurisdiction is imperfect. We don't have jurisdiction over power plants. We don't have jurisdiction—except when they are sold. We review a sale from a market power point of view.

But in terms of building a power plant, it is sited by States under State law. The States have that jurisdiction. States have jurisdiction over the utilities, the State-regulated utilities; and they would be responsible for making sure the State-regulated utility has adequate supply.

We have jurisdiction over wholesale power sales and wholesale power rates. Now there is certainly a relationship between the two, but we, by and large, we don't have jurisdiction over the State-regulated utility and the decisions it makes on how to meet supply. That's typically something that's overseen by the State commissions, the State regulators. We would regulate the wholesale market.

Mr. WESTMORELAND. So you don't have control over the whole grid system?

Mr. KELLIHER. We have jurisdiction over the interstate transmission system, and we have jurisdiction over the wholesale power sales, not wholesale power purchases. The lines—a lawyer can draw the lines neatly. An economist would probably blanch at the notion of some of these distinctions.

States have jurisdiction over retail sales and retail consumers. We have jurisdiction over wholesale power sales and utilities when they are selling power for resale. Any sale that is not to an ultimate consumer, like an industrial or residential consumer, we would have jurisdiction over because that is a wholesale sale or a sale for resale. But you have two markets, retail and wholesale market. One is federally regulated and one is State regulated, but they clearly have effects on one other.

Mr. WESTMORELAND. I was going to say that.

Thank you, Mr. Chairman.

Mr. ISSA. Thank you, good round of questioning.

Mr. Kucinich.

Mr. KUCINICH. Thank you very much, Mr. Chairman.

Mr. Kelliher, does the FERC monitor utility efforts to ensure reliability of the transmission system?

Mr. KELLIHER. We are currently in the process under EPAct—before the Energy Policy Act was enacted, FERC had no authority to enforce reliability standards, let alone penalize anybody for violating reliability standards. I think that is one of the effects of the August, 2003, blackout. Congress gave us that authority.

We are in the process of reviewing 102 proposed reliability standards, and we will soon propose adopting certain aspects of those standards. We are also in the process of certifying an electric reliability organization. We are really faithfully executing the model that Congress set up where what Congress wanted was to be a self-regulating organization, an industry organization. We would certify them if they had the expertise and independence to develop the reliability standards. We would review and approve them, make them enforceable. But the first responder on enforcement would be regional entities and the electric reliability organization. We would be the ultimate enforcer.

Mr. KUCINICH. Well, in connection with that, then how do you ensure utility maintenance? Are you monitoring utility maintenance? And, if not, who is?

Mr. KELLIHER. Maintenance that is necessary to comply with reliability standard, we would ultimately ensure—we would ultimately enforce those requirements. We would do so through audits. We would do so through the prospect of civil penalties of a million dollars per day per violation.

Mr. KUCINICH. What degree of granularity do you have here? For example, going back to our experience of 2003 which made many of us in Ohio experts on utility blackouts, we know that the utility in question, First Energy, was not properly maintaining their transmission system.

Mr. KELLIHER. Yes, sir.

Mr. KUCINICH. So my remarks earlier about how—you know, what are we doing in 2006 that we didn't do in 2003? How specific is the monitoring of the utility performance on a critical issue of maintenance?

Mr. KELLIHER. Maintenance in terms of tree trimming?

Mr. KUCINICH. Maintenance in terms of transmission.

Mr. KELLIHER. Well, the principal maintenance—let's hypothesize the principal maintenance with respect to a transmission facility is vegetation management. Vegetation management has been a common cause to all the regional blackouts that have occurred in this country going back to the 1960's, so it is going to be——

Mr. KUCINICH. I am not talking about vegetation management. I am talking about vegetating management. I'm talking about management which is not hiring enough people to do the maintenance.

That was one of the issues in Ohio, by the way. You can have a great plan for managing trees interfering with transmission lines or distribution lines, but if you don't have enough people—this is the fundamental question. What I saw in Ohio is that First Energy was actually laying off people who would be used to be able to keep the transmission lines clear.

My question again to you is, how specific would be your monitoring of utility maintenance of the transmission systems?

Mr. KELLIHER. The way the law was structured was most enforcement would be done at the regional level with regional entities—we would approve a delegation of enforcement authority from the North American body, the electric reliability organization, to regional entities. We would in turn oversee both the electric reliability organization and the regional entities.

It is critical that the regional entities' enforcement be strong and credible and consistent. Ultimately, I think what would ensure that a company subject to reliability standards complies with those standards was a million dollars a day multiplied over a year ends up being a pretty substantial amount of money. And that kind of violation—let's assume somebody violates the vegetation management standards. That would be a continuing violation every day for a sustained period of time, and a million dollars a day times 365 starts becoming significant. And I think it gives—you were concerned about financial incentives. I think it gives them a financial incentive to have a strong maintenance program.

Mr. KUCINICH. Thank you.

I have just one quick final question. I see in your report you say, with respect to Ontario, our concern is the effects that Ontario demand may have on U.S. markets, and you go on to say that demands for emergency energy could make balancing supply and demand in New York and in the Midwest more difficult and more costly.

Are you then saying that if Ontario has a need for emergency energy it could have a negative effect on the supply in New York and the Midwest, thus increasing the price of power to consumers in these regions? And if you are saying that, how much of a price increase could people be looking at?

Mr. KELLIHER. I couldn't estimate what a possible price effect might be.

But, as you pointed out earlier, on August 14, 2003, an event in Ohio led to blackouts in Canada and then through Canada into New York. These markets, they are physically interconnected; and there is also significant transactions throughout the interconnected markets. So there can be price effects. As we saw in the West, incidents in California extend across not just 11 States but two Canadian provinces. So it can happen.

Mr. KUCINICH. Thank you, Mr. Chairman.

Mr. ISSA. With that, we go to the lightning round in order to get the chairman out of here when we leave for our votes.

Mr. Bilbray.

Mr. BILBRAY. Mr. Chairman, both the Los Angeles and San Diego region is a nonattainment area under the Clean Air Act. Over the last 20, 30 years, there has been no new facilities produced in those areas for good reason. As a former member of the Air Resources Board, I have seen the numbers on reducing emissions, not increasing them. How do we develop the type of reliable sources? Strictly by bringing in outside sources? Or can we do it internally?

Mr. KELLIHER. Well, that's one of the challenges. Southern California does rely very highly on imports. And if you look at another area that was addressed in the Summer Assessment, New York City, New York City has a rule, an 80/20 rule that they have had since the late 1970's or early 1980's. Their general rule is 80 percent of the generation of the supply needed to meet New York City demand has to come from inside New York City, and they want to limit their dependence on imports to 20 percent. I think that's something that is fairly unique to New York.

A load pocket—southern California has a load pocket, New York City and Long Island have load pockets, load pockets where there is high demand, very thin margin between supply and demand, difficulty in adding generation within the load pocket for various reasons but environmental considerations being one of them.

In some of the load pockets, if you see that tight balance, generation can be a solution. Transmission can be a solution. Sometimes you need both. Sometimes you need to lean more on one area than another.

Now in California they do recognize the problem, and they seem to have an interest in leaning more on a transmission solution than perhaps a generation solution in southern California. Perhaps Mr. Mansour can address that in the second panel. But they are significantly expanding transmission in California. They are making significant investments. In some respects perhaps they are catching up to—in those investments in areas where there has not been much in recent years. It really will vary from region to region.

It is an issue that we have to deal with because we're looking at the mid Atlantic States where New Jersey regulators, our colleagues in the State, argue that there is a very tight supply and demand in balancing northern New Jersey, but it is very difficult to build generation in northern New Jersey and they think a transmission solution is necessary more than a generation solution. So it really will vary. It is difficult to build generation in some parts of this country.

Mr. BILBRAY. The perception that transmission is the environmental option has kind of run into problems in southern California, too, where you have a transmission proposal going through State parks.

Has anybody talked about the fact that in local utilities we tap into general purpose governments to do siting, but when it comes to transmission capabilities we don't draw on the Council of Governments [COGs]? We almost leave it up to the project proponent to find these alignments and sort of like it is their problem, not our problem, in government to be able to find the best economic and environmental opportunity to be able to site these things. Has anybody talked about including that as the responsibility of the Council of Governments?

Mr. KELLIHER. I'm not aware of that.

A lot of utility executives say the reason they don't build much transmission—they don't spend more, they haven't in the past, it is the hardest thing to get done. It is easier to build generation than transmission is what you hear frequently. I think that is one reason that Congress changed the law and provided for some Federal siting jurisdiction.

Mr. BILBRAY. As somebody who comes from local government, it is always easier to say no and how terrible the proposal is to either put the facility or the transmission capabilities in. But local government and regional government have never been given the responsibility to be proactive and say, OK, you don't like this proposal. Where is the best proposal, as you see it, and be proactive about siting that ahead of time. We site the subdivision, but we never want to site the transmission lines.

Mr. KELLIHER. Yes.

Mr. ISSA. Thank you. You stayed well within the time. I appreciate that.

As promised, we are running out of time because of the vote.

Mr. Chairman, I am going to give you a very few questions and ask you, if they are yes-nos—which they are not—to answer them. Otherwise, we will take the rest in writing to allow you not to wait 25, 30 minutes for us to return.

Mr. KELLIHER. Thank you.

Mr. ISSA. And my apologies to the ISOs, that it is impossible to not ask to you please be patient.

In your testimony, you talked about the failure of the two lines in upstate New York into New York City. It didn't actually get into the details of what caused the failures, and I would appreciate if you would make the record complete by, when available, giving us more information on the specifics of those failures. Particularly, we have one—the ranking member has left——

Mr. KELLIHER. I will provide that for the record.

Mr. ISSA. I appreciate that.

Obviously, one of the questions is one that may be more difficult and beyond the Assessment. Since these trouble spots have been on the record 2004, 2005 and now 2006, what is it going to take to have them removed from X-year? I think we all realize that some of them are going to be back on in 2007, and the ISOs particularly today will talk to us a little bit about their regions and how they are getting out of it.

But to the extent that the FERC believes they know the minimums necessary to take them off the list, that would be helpful that you give us your vision of it, which would be hopefully similar to the ISOs.

The growth of renewables in California and the mandating of renewables—obviously, we are thrilled to have as much clean renewable energy as we can, but I would appreciate it if you would give your feeling on how it makes reliability more difficult. In California specifically, where we have a lot of wind, it is reliable that we have wind. But that we don't have it when we need it is also reliability predictable.

So to the extent you can show the impacts—obviously, that is going to impact advanced transmission and pump storage and how the two relate. You don't have to be exhaustive. I don't want you to go beyond what you would give reasonably here today.

Last but not least, in my opening statement or in my opening sort of question, I said I am extremely interested in how the FERC is going to, from a process and time line basis, get to valuing pump storage in order to define what advanced transmission is and why it can be incorporated at X-price by our ISOs. Because today it appears as though we have a great relief valve for some of these peak needs. Unfortunately, if you have a mountain and you have a siting of a transmission line but you don't know what the value of that pump storage is, those projects are not going to go forward.

I know that we will hear from the ISOs, and they will give us some insight. But to the extent you can show us a process and time line, that would be very helpful. If you have any responses before you throw me out of here.

Mr. KELLIHER. Could I respond to those questions for the record in writing?

Mr. ISSA. Absolutely.

With that, I would like to thank all of you for your patience in advance for about a 20 minute delay, and then we will convene the second panel. We stand in recess.

[Recess.]

Mr. ISSA. This meeting of the subcommittee will come back to order. I appreciate your patience as we went through our obligation—the thing that we use as an excuse for rudeness so often here.

With that, you have already been sworn in.

Your opening statements, as I said earlier, by unanimous consent will included in the record.

I appreciate you using roughly 5 minutes.

With that, Mr. Mansour, I guess you get the leadoff; and all you have to do in your opening statement, of course, is respond to everything that the FERC had to say earlier. You get that responsibility. Thank you.

Mr. MANSOUR. Do I get the time allowance as well, Mr. Chairman?

Mr. ISSA. By unanimous consent, so ordered.

STATEMENTS OF YAKOUT MANSOUR, PRESIDENT AND CEO, CALIFORNIA INDEPENDENT SYSTEM OPERATOR; MARK S. LYNCH, PRESIDENT AND CEO, NEW YORK INDEPENDENT SYSTEM OPERATOR; PETER BRANDIEN, VICE PRESIDENT OF SYSTEM OPERATIONS, NEW ENGLAND INDEPENDENT SYSTEM OPERATOR; AND PHYLLIS E. CURRIE, GENERAL MANAGER, PASADENA WATER AND POWER

STATEMENT OF YAKOUT MANSOUR

Mr. MANSOUR. Thank you very much; and good afternoon, Mr. Chairman, committee members and honored representatives.

My name is Yakout Mansour, and I am the president and chief executive officer of the California Independent System Operator Corp., that I will refer to as ISOs as I go. I joined the ISO in March 2005, so it has been over a year, but I have been intimately involved with the western electricity market for many years.

It is a pleasure and honor to be here today to discuss the electricity outlook in southern California for the summer of 2006, our efforts to overcome the challenges we are facing, and the steps that have been taken to address the long-term needs of California.

Just in case I lose my time allowance, Mr. Chairman, in a nutshell, California, since restructuring and actually since the time of the crisis, has added 14,000 megawatts of new generation. We retired over 6,000 megawatt of inefficient and socially unfriendly resources, old resources already. So the net is 8,500 or so, but the effect remains that we have 14,000 megawatt of new generation in California.

$3.5 billion of transmission have already been in the ground and $4.5 billion have been approved in total, including that $3.5 billion. In the process as we speak, between the utilities of southern California, Edison and San Diego, there is about $6 to $7 billion of transmission projects.

But that is not enough. This is California. That is growing fast. We are firing on four cylinders at the same time. We are catching up on a period where investment was not enough.

As was mentioned, there was a lack of investment for a long time before restructuring, and that is actually what drove restructuring. We are retiring the old fleet. We are accommodating one of the most aggressive renewable programs in the country, if not the most. The fourth one is accommodating one of the strongest economic growths.

Compared to a year ago, which is last summer, now this summer we are about at the same level as we were last summer in terms of our stress of the grid. From last summer until today, we have 1,900 megawatt of new generation. They are both in the south, which makes up for more than the retired old, which is about 1,500 megawatt. That is including Mojave in the south and Hunter's Point. Both were publicly opposed projects.

Now the net is modest, yes, 300 or 400 megawatts between the 1,900 which is significant and what we have retired. But the fact remains from last summer until this summer we have 1,900 megawatts of more efficient and reliable generation.

The grid import capability has been increased by about 800 megawatts. Our grid reliability cost, what we call the congestion cost, have decreased by over 40 percent. In 2004, it was over $1 billion. Last year, it was around $600 million.

We have a very pleasant increase in the subscriptions to the demand response and interruptible programs, especially those in the south and those in the north. All are very active and all the participants are very active in promoting conservation. There are more intensive efforts to promote conservation; and the Governor never misses a chance to promote conservation, whether at a private meeting with us or public meetings.

Last year, the State consumers were credited with about 800 megawatt due to conservation. So what does the picture I refer—

I think someone is operating a computer slide for me. If you could press the first slide. Next one.

For California overall, the total control area supply is about—close to 52,000 megawatts, and that is after excluding 4,000 megawatts of outages, possible outages. The most likely demand for California is just over 46,000 megawatts; and, Mr. Chairman and members of the committee, we are—I think we may achieve this, actually, that forecast, by the end of this week.

So that leaves us about 12 percent margin. By the way, we need about close to 7 percent margin for operating reserve. If we account for the response of interruptible programs which we only use in emergencies, that would be 24 percent.

But this is the interesting thing. Those programs, people are paid actually in advance to be ready to be interrupted if we need them to. But to do that we have to say it is an emergency so we make the news, and we have to interrupt, and they make the news again. It is called then something we lost load, but, actually, they are paid to do it, and they are part of the program. We would like to see more of that.

Next slide.

For southern California, the load forecast is about 30,000 megawatts—sorry, 27,000 megawatts; and the resources available are 30,000 megawatts, as we mentioned earlier, about 10,000 megawatts, 30 percent of that on import. But California and the West have invested over the years billions of dollars on the transmission grid to make that possible. This is a good thing, because it capitalizes on the regional diversity both in resources and weather. So that leaves us in southern California 10 percent.

You see the margin between 10 percent and what is needed for operation is 7 percent is only 3 percent, and that is what we call tight. If we include the demand response and interruptible programs, that would be about 20 percent.

The next slide, please.

That is a pictorial that, when we say tight, how tight are we and what do we mean? The numbers that I've just presented to you represent the middle part of this graph, the middle bar in this bar chart. And you can see under the most likely condition the green line, even with accounting of up to 2,000 megawatt loss of import capability, we have slightly more than what we need to have. If you account for the interruptibles, you can almost be close to the extreme 1 in 10 in terms of load. That is based on additional 1,500 megawatt outage.

Now if you go to the left, things get really extreme. If you have very high load and you have higher outages on generation and you have a 2,000 megawatt loss of import, you get closer to the possibility of tripping firm load. Now how far you go to the left to say we're comfortable, this is a measure of public policy, how much the public is willing to spend and the cost to make more available to California in those extreme conditions.

So as operators, of course, regardless of how slim the chance of the slim conditions is, we prepared for the worst. So what do we do for the short term?

Next one.

For the short term, we're conducting operator workshops. We have so far trained over 300 operators nationwide, promoting conservation together with all the agencies and the Governor's office. We are engaging all the suppliers and the power plants, coordinating maintenance. We are completing all the upgrades in the grid, improving communications with LADWP and Bonneville, implementing new market rules, and we are improving the forecast.

For the long term—this is my last piece. Next slide, please.

For the long term, 2007 is likely to be as tight or even a bit tighter than we have today, because we don't have as many generation plants from last year to now. But we have a break of the deadlock. The utilities would not go long term because they were not assured cost recovery, and the market rules that we have today—the original market design that we have today before we get to the new market design doesn't give them really comfort to invest. So there is a new proposed ruling from the PUC that will get close to 4,000 megawatts by 2009.

So, hopefully, 2009 for sure, that we are going to be OK. We hope that we can get some by 2008; 2007 for sure is going to be tighter. We are going to get the first two.

After that, the transmission development—we don't call it transmission planning; we call it transmission development—is streamlined. We are currently identifying and studying major projects: Sunrise, Greenpath, Tehachapi and Lake Elsinore. We're talking about $5 billion, as I said; and the last is the market tools which is the market redesign and technology upgrade.

In this respect, yes, we're tight under extreme conditions, but we have plans to minimize the impact and hopefully squeeze by. In this respect, I am confident we have the ingredients that we need. The long debates about let us do more studies or, you know, give us more time to do new things, I think we should be past that.

Overall, I can say, yes, we're tight, but not to the point where the lights will be off all the time. It is going to be maybe sometimes. Last year, we were as tight. We had one of our best operations ever. Are we going to have some lights off? Hopefully not, but we're prepared to minimize that impact.

Thank you, Mr. Chairman and members of the committee.

Mr. ISSA. Thank you.

[The prepared statement of Mr. Mansour follows:]

G01 93 221-4

Prepared Statement
Of
Yakout Mansour
President and Chief Executive Officer
California Independent System Operator Corporation
Before the
U.S. House of Representatives
Committee on Government Reform
Subcommittee on Energy and Resources
July 12, 2006

Good afternoon, Mr. Chairman, Committee members and other honored representatives. It is a pleasure and an honor to be here today to discuss the electricity outlook in Southern California for the Summer of 2006.

My name is Yakout Mansour and I am the President and Chief Executive Officer of the California Independent System Operator Corporation ("California ISO" or "ISO"). I joined the ISO in May, 2005, but I have been intimately involved with the Western electricity market for many years.

California's electricity system is critical to ensuring the safety and economic health not only of California's citizens, but of all citizens and consumers in the Western United States. The ISO facilitates thousands of wholesale electricity transactions on a daily basis to help ensure that supply meets demand in real time. Additionally, we ensure a reliable grid through a transmission planning process and development of transmission maintenance standards.

The California ISO is the largest control area, in terms of load and peak load served, in the Western Interconnection. It is the only control are that is completely independent of a financial interest based on how it operates and meets reliability criteria, and it is dedicated to ensuring a safe, reliable and affordable transmission system. We are working closely with stakeholders, California State agencies, federal agencies, our regional partners, and consumers at large to accomplish these goals.

I want to report to you that, while more work remains to be done, we have seen some extremely positive developments in California. From an operational perspective, 2005 was an outstanding year for the ISO, in which we met or exceeded all control performance standards. Our market monitors found the California ISO's markets stable and competitive for the fourth year in a row. We have realigned the organization in order to streamline and refocus our work activities; as a result, we have been able to reduce our budget by almost $13 million and, as a result, file our lowest Grid Management Charge ("GMC") since ISO start up. The ISO's filed GMC (on a bundled basis) was reduced 15% from 2005 to 2006 and, over the last three years, has been reduced by 27%. Improvements and upgrades to the ISO-controlled grid are showing their value as congestion costs have been reduced by 50% in the last year as well. Most importantly, as I discuss further below, we are seeing continued investment in the State's critical electricity infrastructure.

I have structured the balance of my testimony to focus on the issues you requested that I address. First, I provide the ISO's perspective on 2006 summer operating conditions. Second, I identify some of the shorter-term strategies and activities undertaken by the ISO to prepare for summer and to further reliable operation of the grid. Third, I will discuss some of the key longer-term strategies and programs underway in California to address California's ever-increasing demand for electricity and the need for new, reliable and environmentally-friendly resources.

Summer 2006 Loads and Resources Assessment

In April 2006 produced its annual Summer Assessment. The ISO's assessment concluded that under the average predicted conditions, the ISO should have more than sufficient resources to meet demand, both on a system-wide basis and in Southern California. While the ISO's assessment also found that under more extreme system conditions we could be presented with reliability challenges in Southern California this summer, I am confident we have sufficient resources to serve load under a wide range of systems conditions.

The Federal Energy Regulatory Commission's May 18, 2006 Summer Energy Market Assessment ("FERC Summer Assessment"), referencing the ISO's study, generally concurred with the ISO's findings. In addition, I believe that the FERC's assessment is generally consistent with FERC's earlier findings in 2004 and 2005, as well as with the projections made by the California Energy Commission and the California Public Utilities Commission (CPUC).

As stated above, in April 2006 the ISO released its ISO's 2006 Summer Loads and Resources Assessment. The ISO prepares such an assessment prior to every Summer and Winter operating season. As shown, the ISO's assessment shows that on a system-wide basis, there is sufficient supply capacity to address ISO control area needs. Under the "most likely" scenario, California's Operating Reserve Margin statewide is projected to be approximately 12%; well above the 7% minimally acceptable daily reserve margin. "Most likely" conditions include average temperatures, all major transmission facilities in service, average projection of economic conditions, average forced outage rates for generation, known generation retirements and "most likely" import conditions.

With respect to Southern California, under normal operating conditions we estimate that we will have a peak demand of 27,299 MW in the area south of Path 26 ("SP26") this summer. Total generation capacity, including forced and planned outages, amounts to 19,976 MW and imports are projected at 10,100 MW, leaving 2777 MW in excess or "unloaded" capacity.

It is critical to emphasize that even with the loss of a major transmission line and higher than expected generation outages, the ISO should have more than sufficient resources to serve load under the "most likely" conditions and a wide *range of other system conditions, even without calling on the contracted interruptible load resources available to the ISO.*

As the FERC assessment has predicted, the capacity picture south of Path 26 may be a source of concern under "extreme" conditions, e.g., unlikely conditions. "Extreme" conditions are those in which electricity demand is higher than expected due to extreme weather conditions, such as very high temperatures and the low availability of hydroelectric resources. Such conditions are typically referred to as "one in ten" conditions – conditions that are likely to exist only in one out of every ten years. As forecast by the ISO, demand south of Path 26 could exceed 29,560 MW under such conditions. With a total generation capacity of 19,976 MW and imports at 10,100 MW, a margin of 516 MW would exist. Once again, however, such conditions are very unlikely. That notwithstanding, it is critical that the ISO develop operating plans that will enable it to operate the grid safely and reliably. I discuss this issue further below.

I note that subsequent to April we have made certain refinements to our assessment. Since we prepared the summer assessment a few things have changed. First, while we had estimated a net generation addition of 370MW for Summer 2006, subsequently announced retirements and additions result in a net loss of generation of 42MW. In addition, the California Energy Commission has raised their estimate of available Demand Response and Interruptible resources from 1840MW to 1927MW. The net affect of these changes is insignificant and does not change the bottom-line conclusions of our earlier assessment.

Under the conditions identified in the assessment, the ISO anticipates that it will continue to satisfy all applicable reliability standards, as established by the North American Electric Reliability Council ("NERC") and the Western Electricity Coordinating Council ("WECC"). The NERC and WECC standards are *operating* standards and are meant to define and guide reliable operation of a power system on a day-to-day and moment-to-moment basis. The ISO's loads and resources assessment is part of a typical planning exercise and the "most likely" conditions (loads and resources balance) are within generally accepted system planning standards. Examination of system conditions under "extreme" conditions is necessary to properly prepare for *operations*, but no one should assume that the identified potential supply deficiencies under the "extreme" system conditions are necessarily a problem that must be entirely addressed through the addition of new resources, i.e., that the system should be *planned* to that level of reliability.

Historically, utilities have added resources in accordance with certain predefined standards that reflect a set amount of risk of load curtailment. For example, traditionally, many utilities have built their systems to satisfy a Loss of Load Probability ("LOLP") of one-day in ten years. That is, they have added resources and built infrastructure to ensure that they will not have to drop load more than one day in every ten years. While not precisely based on such a standard, I believe the CPUC's adopted resource adequacy requirements, e.g., the 15-17% planning reserve margin, are meant to approximate such a standard. I believe this is an appropriate balancing of risk and costs and that it would be exorbitantly expensive to build resources and infrastructure so as to either completely mitigate, or substantially reduce, the likelihood of firm load curtailment. It just would be too expensive to add resources so as to ensure service reliability one hundred percent of the time. That would not be a cost-effective approach to both planning and operating an electric power system and would not be in the best interest of consumers.

It is also important to remember and consider that operating conditions are influenced by a number of factors including not only temperature and the availability of generating resources, but also the operation of transmission facilities. The loss of a major transmission facility due to mechanical failure, wildfires, or other contingencies can greatly impact grid reliability by reducing the amount of power that can be imported into California or restricting the ISO's ability to redispatch the system and transmit power where and when needed.

To that end, since the end of last summer the ISO has focused significant attention on the development of operating plans and tools to prepare for a reasonable range of probable conditions, including the adverse system conditions identified above. Development of these plans and tools is necessary to ensure that the ISO can both anticipate, and take timely action to address, operating conditions on the system. To develop such plans, the ISO performs operating studies to determine what facility, if lost, would have the greatest impact on the ISO's ability to reliably operate the system. This is often referred to as the "Most Severe Single Contingency". A "single contingency" is, for example, the loss of either a major transmission line or substation, or the loss of the generating unit.

For purposes of studying Summer 2006 operating conditions, the ISO has identified the loss of the Pacific DC Intertie ("PDCI") as the "Most Severe Single Contingency." The PDCI is a major transmission path that runs from the Pacific Northwest down to Los Angeles, California, and is critical for bringing required imports from the Pacific Northwest to areas in southern California. The power transmitted on the line is used to serve load both inside and outside of the ISO's control area. Loss of the PDCI at any time requires that the ISO implement significant contingency procedures. Since the beginning of this year, outages on this line have occurred with great frequency. Sixty-four (64) forced outages have occurred on the PDCI from January 1 through mid-June of this year. . Should such outages continue they could seriously impact the reliability of power supplies in California. The ISO's study shows that if the PDCI is lost, dispatching the required amount of energy to make up for the loss would be a major challenge. If the Southern California load is higher than average, the import capacity/availability is less than normal, the amount of generation out of service is higher than normal, or if there is a sustained outage of another major transmission line, the capacity margins could be exhausted and the ISO may have to implement load curtailment to ensure grid stability. This scenario is, of course, not limited to loss of the PDCI, but recent experience has increased our concerns about the potential for this to occur. The ISO continues to work closely with the Bonneville Power Administration, and the Los Angeles Department of Water and Power, who is responsible for the physical operation of the line, to identify the causes of the outages and to address operational and communications issues among the parties. We are encouraged by the concern that the staffs of Bonneville and LADWP have shown and the steps they have taken to diagnose issues and improve coordinated operations. I want to emphasize how crucial this communication and coordination will be going forward as we meet the challenges of our ever-increasing demand for electricity.

In summary, although both the ISO's and FERC's assessment are consistent in anticipating that electricity supplies will be tight in Southern California in the summer of 2006 and for the next two years, the ISO should have sufficient resources to serve load under a wide range of operating conditions. To address the existing circumstances, the ISO has been working with utilities, generators, and other control area operators in the West on strategies for the summer of 2006 and beyond.

Short-Term Strategies to Prepare for Summer 2006 Operations

As I explained earlier, since last year the ISO has been preparing the operating plans and tools necessary to ensure that the ISO can operate a safe and reliable system. These operating plans and tools are designed to ensure that the ISO meets all generally-accepted operating standards, as established by the North American Electric Reliability Council ("NERC") and the Western Electricity Coordinating Council ("WECC"). Specifically, the tools and procedures are designed to allow the ISO to both anticipate and take timely action to address all operating conditions. Toward that goal, the ISO has developed an operating tool that will allow the ISO to determine the resources it will need, both in quantity and location, to reliably operate the system under various contingencies, including, as explained above, the Most Severe Single Contingency. Based on that determination, the ISO will then be able to ensure, on a day-ahead and hour-ahead basis, that all available capacity resources are committed and deployed effectively to address contingencies, with a specific focus on the SP26 region.

Capacity resources include those made available through the ISO's ancillary service markets, real-time energy market, or pursuant to the ISO's more general authority to commit resources under its FERC-approved tariff. In addition, and perhaps most importantly, as of June 1, 2006, capacity resources procured pursuant to the CPUC's "Resource Adequacy" program are available to the ISO for commitment and dispatch. Under the requirements of that program, load-serving entities under the CPUC's jurisdiction are required to procure and make available to the ISO the capacity resources necessary to serve their load, plus a reserve margin. I discuss the CPUC's Resource Adequacy program further below.

To ensure a complete and thorough understanding of how the ISO intends to reliably operate the system this summer, the ISO has worked extensively with the Governor's Office, the CPUC, the Energy Commission and other state entities to ensure effective and coordinated operations among and between the ISO and state entities. Such coordination and communication is critical not only to ensure reliable operation of the entire system but also as a means to develop and elicit effective conservation efforts throughout the state. Investor-Owned Utility administered demand reduction programs have increased approximately 250 MW between 2005 and 2006, offering a total of 1840 MW for this summer. Furthermore, the ISO has rolled out our annual summer conservation campaign, which allows the public to know twenty-four (24) hours in advance of when conservation is needed during specific times and regions of the state. We estimate that this program alone generated approximately 800 MW on hot days last year.

In addition, the ISO has been working closely with all market participants to ensure that they understand the ISO's operating strategies and plans and can partner with the ISO in maintaining grid reliability this summer. In early June, the ISO successfully concluded its "Summer Seminar" training exercise, involving participation by over 300 operating personnel from the investor-owned and municipal utilities and other public power entities. The ISO also held specific meetings with the IOUs, municipal utilities and suppliers to share with them our proposed summer operating plan. These activities have provided valuable opportunities to communicate information so that all parties are fully prepared for summer operations.

The ISO has worked closely with the load-serving entities to secure additional contracted resources (interruptible loads) south of Path 26 for the summer of 2006. In addition, in order to maximize the amount of transmission capacity and availability into both California and the SP26 region specifically, the ISO is working with transmission owners to ensure that all maintenance and outage programs are well coordinated during the summer season and that transmission projects are completed on time. Working with transmission owners, the ISO has identified both infrastructure upgrades and "softer" projects, such as remedial action schemes, that will allow us to import 800 MW more than usual this summer. In addition, an additional 1400 MW in transmission capacity has been added this summer.

The ISO has also worked with neighboring control area operators to discuss supply and demand outlook and to determine areas of excess/deficient supply. Finally, the ISO has worked with both load-serving entities and transmission owners to develop a plan for interruptible and firm load curtailment should such actions be necessary in response to "extreme" system conditions.

On the supply side, the ISO continues to work with suppliers, both public and private, to ensure a complete and accurate understanding of the anticipated operating environment. In addition, in order to maximize the availability of all supply resources, the ISO is working with the owners of all generating plants to coordinate all necessary planned outages and to emphasize the need for timely notification of unplanned outages. The supply community has been very responsive and I believe the suppliers are a committed partner in ensuring the reliable operation of the grid this summer.

Furthermore, in anticipation of the possibility of tight supplies this summer and the need to better position the ISO (and California more generally) to compete for such supplies, the ISO Governing Board authorized, and FERC approved, an increase in the bid caps in the ISO's markets from $250/MWh to $400/MWh. Although the increased bid caps are still the lowest among the established Regional Transmission Organizations ("RTOs"), I believe the increased bid caps provide suppliers additional and appropriate bidding flexibility. Such flexibility should better enable suppliers to cover their marginal costs while securing a reasonable contribution to their fixed costs. I note that the May 18 FERC Summer Assessment found that even with the increase the bid caps that average energy prices have not been affected much.

I am pleased to report that such coordination with market participants has already paid dividends. On June 22, 2006, the PDCI was forced out of service. Loads on the system were high as a result of high temperatures. As a result of PDCI outage, the ISO was forced to cut 600 MW of schedules on the PDCI, thus limiting the amount of power flowing into Southern California. The ISO immediately implemented contingency procedures to ensure both the continued reliable operation of the grid and uninterrupted service to customers. The ISO dispatched available capacity and system frequency was returned to the pre-disturbance level within fourteen minutes. In addition, the ISO experienced no overloads on other major transmission paths (frequently, with the loss of a major transmission line, power will flow onto other in-service lines, potentially causing those lines to exceed their rated capabilities). The ISO was able to successfully address this contingency because of prior planning and the fact that it has previously committed available generation in anticipation of the need. While such events are not unexpected and all system operators must be prepared to address such situations, this event provides a good example of the need for good operational planning and how the ISO is prepared to address contingencies that may arise this summer.

Long-Term Investment Strategies

Although tight reserve margins exist and are likely to persist over the two years, investment in California is on the right track. Since 2001, approximately 14,950 MW of generating capacity has been added in California. About 2300 MW of new generation has been added in Southern California alone since January, 2005. In fact, there was more new generation investment in California in 2005 than in any other regional transmission organization footprint. As FERC accurately reported in its Winter 2005/2006 Energy Market Update, California tripled its new investment in power plants since 2004. There were also a significant number of generator retirements during this period, resulting in a net loss of generation of 42MW for 2006. However, the replacement of old, inefficient, polluting plans with clean and efficient units is in itself a benefit to the State and its citizens.

We are also seeing investments in new transmission infrastructure in the state. We have been working closely with transmission owners to identify, gain approval and then accelerate construction of transmission upgrades. Transmission projects now in the planning stages will not only supply needed transmission to Southern California, but will help the development of renewable resources to meet the state's aggressive Renewable Portfolio Standard for electricity generation of 20% by 2010. Three important projects that the ISO is currently studying include the combined Sunrise Powerlink and Greenpath projects in San Diego and Imperial counties, the Tehachapi transmission planning effort, and the Lake Elsinore Advanced Pump Storage ("LEAPS") project in southeastern Riverside County. The Sunrise/Greenpath projects would enable 2000 MW of geothermal and solar resources to come on line. The Tehachapi project is designed to bring 4000 MW of wind resources to the grid by 2010. The LEAPS project is planned to be able to pump water to an upper reservoir when electricity is abundant (nighttime) and generate electricity when needed most (daytime). The LEAPS project would allow 500 MW of energy to be stored to help address the intermittent nature of the wind resources in the Tehachapi project was well as to improve water quality in the lake itself. The ISO is currently studying has not yet made a final determination as to the need for any of these projects, the ISO is committed to identifying, evaluating and ultimately, if appropriate, building needed new transmission lines. The Sunrise/Greenpath project is likely to come before the ISO Governing Board for approval at its August 3rd meeting. The Tehachapi and LEAPS projects are likely to be addressed shortly thereafter, although the ISO is awaiting certain decisions from FERC regarding the LEAPS project before it can make a final determination regarding that project.

In addition, many ISO stakeholders have identified the cost of transmission facilities as a significant barrier to the development of renewable generation, especially in geographic regions with little load but vast potential for renewable energy supply. In response to this input, the ISO is exploring the development of a new approach to promote construction of transmission facilities that are necessary for renewable generating resources. We are now reviewing options and strategies for new evaluation criteria and cost recovery policies that will remove barriers to development of renewable generation in the West, including the possibility of a distinct category for "renewable generator supply transmission lines" that would be eligible for alternative cost recovery treatment. FERC will ultimately resolve the policy questions related to these issues.

Finally, in addition to the three major projects discussed above, the ISO also anticipates $1.8 billion of additional transmission investment over the next five years in Southern California alone. Such new investment will enhance the ISO's ability to both import needed power into Southern California, but also to deliver it where it is needed.

On a long-term basis, the best means to address the tight supply conditions in Southern California is to create a market and regulatory environment that attracts new investment in the state's critical energy infrastructure. I am now more encouraged than ever that such an environment has now returned to California and will continue to flourish. Policymakers throughout the state – be it the Governor's Office, the CPUC, the CEC or other state entity – are on the same page and through their concerted efforts are creating the policies and rules necessary to attract new investment.

The Governor's Office is strongly promoting new infrastructure development and is leading the way in facilitating the development of new, environmentally friendly new resources. Strongly supported by both the Governor's Office and the State Legislature, the state's Renewable Portfolio Standard ("RPS") policies are one of the most aggressive in the country, setting as a goal to have 20% of the state's energy requirements satisfied by renewable resources by 2010 and 33% of the state's energy requirements satisfied by renewable resources by 2020.

On a broader basis, the CPUC has taken a number of very important steps over the past few years to establish rules that will promote the development of new infrastructure in the state. Without question, the best means to secure new electric infrastructure is to ensure that load-serving entities have both the obligation and ability (certainty) to enter into secure long-term forward contracts with suppliers. Such forward contracts provide load-serving entities - and ultimately consumers - a means to mitigate price volatility and secure stable and reasonably priced electricity. In addition, such contracts provide a stable revenue source to fund new investment – a stated prerequisite for investors in today's energy marketplace.

As referenced above, over the past several years the CPUC has adopted, for the load-serving entities under its jurisdiction, explicit annual and monthly requirements ("Resource Adequacy Requirements") for such load-serving entities to procure the capacity resources necessary to serve their load, plus a reasonable reserve margin of between 15-17%. In conjunction with establishing the annual and monthly Resource Adequacy Requirements, the CPUC has also begun to establish long-term procurement rules that require load-serving entities to identify the resources or means by which they will satisfy their load requirements over the next five to ten years.

In a recent draft decision, the CPUC found that 3700 MW of new generation must come on line by 2009 in order for the state to have adequate capacity and reserves, in addition to the investments that the CPUC-jurisdictional load-serving entities are expected to make in renewable resources. In addition, the draft decision adopts an interim cost allocation mechanism, which will be transitional until a capacity market or other new market institutions are developed, that makes the major load-serving entities (the three California Investor-Owned Utilities) responsible for acquiring new generation capacity, on a temporary basis, for bundled and unbundled customers. Such rules and requirements are critical to establishing a regulatory and market environment critical to attracting new investment.

With respect to the development of new transmission infrastructure, I am very pleased by the level of cooperation and commitment of the CPUC, the Energy Commission, and transmission owners in working with the ISO to develop a viable and sustainable transmission planning and development process in California. Working with the CPUC, Energy Commission and transmission owners, I am confident we can construct and implement a transmission infrastructure process that will deliver real results.

While we are encouraged by the progress made to date, we undoubtedly must realize a significant amount of additional infrastructure development to supply the state's growing electricity needs. We estimate that demand for electricity will continue to grow by 1000 MW per year, consistent with demand growth over the last four years.

Of course, with any mention of long-term strategies, I would be remiss if I did not mention the ISO's own efforts to reform its markets. Late next year the ISO plans to implement a comprehensive Market Redesign and Technology Upgrade ("MRTU") program that will help inform infrastructure development in California. The MRTU program, slated to come on line in November of next year, will also correct flaws in the existing market structure that have existed since the western energy crisis, strengthen the reliability and efficiency of grid operations, reduce costs, and guard against "gaming" and market manipulation. Our proposal has been under development since 2002 and has been the subject of a extensive stakeholder process over the last four years and has received conceptual approved by FERC in four interim rulings. It is based on tried and true market design features that have been successfully implemented in other markets. More importantly, the design is predicated on aligning price signals in the market with reliable operations of the grid. Therefore, the design should further the ISO's goal of reducing reliance on the ISO's spot markets and ensuring that sufficient resources are procured and made available to the ISO ahead of real-time to as to reliably serve load on the system. The proposal is currently pending at FERC.

As you may know, a number of parties have raised issues with respect to the ISO's MRTU proposal and whether it is compatible with the form and function of the larger Western electricity market. I can assure you that the ISO will not implement a market design that will inhibit the function of the larger regional electricity market. Others represent that the ISO is beholden to a philosophy and resultant market design that is based on an exclusive reliance on spot market prices. This is not true. The ISO's MRTU design is a perfect complement, not alternative, to longer-term bilateral contracting and will work seamlessly with the

CPUC's longer-term procurement program. As noted above, the ISO's MRTU design is based on tried and true principles and designs that align the requirements of reliable grid operation with market price signals.

In conclusion, the State of California is making progress on four crucial tasks: building the long-ignored electricity infrastructure; retirement of old, inefficient facilities; accommodating the most aggressive renewable program in the country; and meeting the demands of a healthy and growing economy. It will take the cooperation and coordination of all stakeholders, along with state and federal policymakers, to ensure that these challenging tasks can be realized. In the meantime, one can expect a period of "catch up" reflected by the tight situation we face this summer and in all likelihood the next two years. The ISO looks forward to its role in achieving these benefits for California and the western U.S.

I would like to thank you again for the opportunity to address you today and for your attention to these pressing issues. I look forward to answering any questions you may have. Thank you.

California ISO
Your Link to Power

California Independent
System Operator Corporation

Summer 2006
Loads and Resources Operational Outlook

U.S. House of Representatives
Committee on Government Reform
Subcommittee on Energy and Resources

Yakout Mansour
President and Chief Executive Officer
California ISO

July 12, 2006

California ISO
Your Link to Power

California Independent
System Operator Corporation

Summer 2006 California ISO Control Area Peak Forecast

Most Likely Conditions

▪ Control Area Generation Capacity (includes 4000MW forced and planned outage rate)	42,600MW
▪ Control Area Imports	9,000MW
▪ Total Control Area Supply	51,600MW
▪ Most Likely Control Area Demand	46,063MW
▪ Operating Reserve Requirement	2,856MW
▪ Total Reserve Capacity	5,537MW
▪ Surplus Reserve	2,681MW
▪ Operating Reserve Margin	12 %
▪ Planning Reserve with DR and Interruptible programs	24.6%

California ISO
Your Link to Power

California Independent
System Operator Corporation

Summer 2006 SP26 Peak Forecast

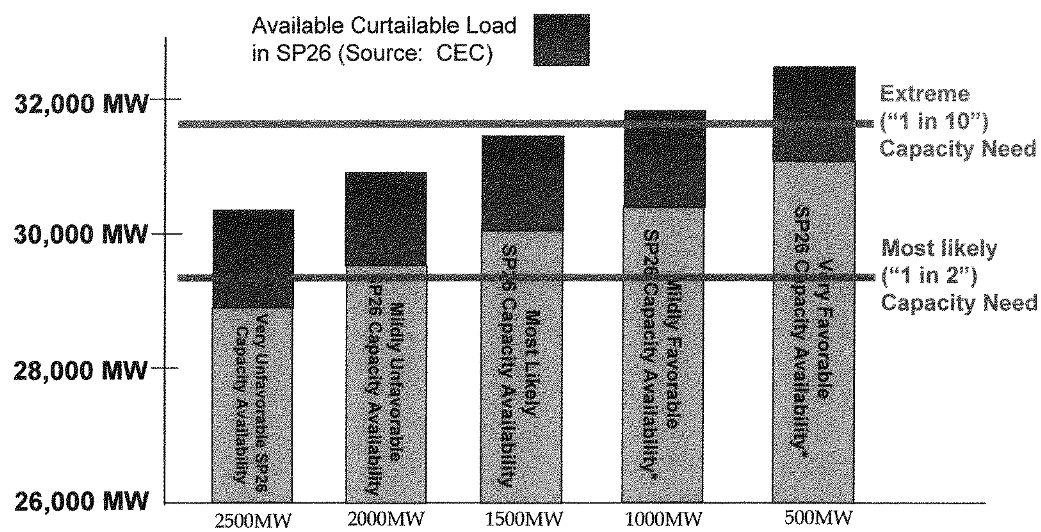
"Most Likely" Conditions

▪ SP26 Generation Capacity (includes 1500MW forced and planned outage)	19,976MW
▪ SP26 Import Capability	10,100MW
▪ Total SP26 Supply	30,076MW
▪ "Most Likely" SP26 Demand	27,299MW
▪ Total SP26 Reserve Capacity	2,777MW
▪ Operating Reserve Requirement	1,690MW
▪ Total Operating Reserve	10.2%
▪ Planning Reserve with DR and Interruptible programs	20%

California ISO
Your Link to Power

California Independent
System Operator Corporation

SP26 Capacity Picture Under Various Generation Outage Scenarios ***and*** Loss of 2000MW of Import Supply



Generation Forced and Planned Outage Rate

4

Short-Term Strategies

- Conduct operator workshops
- Promote conservation
- Engage suppliers, load-serving entities, and transmission owners to assess needs and available supplies
- Coordinate maintenance (generation and transmission)
- Complete upgrades and increase transfer capability (1400MW transfer capacity, 800MW imports)
- Improve communication and coordination with LADWP and Bonneville (PDCI)
- Implement new market rules (e.g., Price Caps)
- Improve short-term forecasting process
- Develop operating tools and procedures

Long-Term Strategies

- CPUC long-term procurement program (3700 MW by 2009)
- CPUC Resource Adequacy – Phase II (capacity markets)
- Identify, study and approve needed new transmission lines (e.g., Tehachapi)
- Support transmission needed for renewables
- $1.8 billion in transmission investment in Southern California over the next 5 years
- Streamline transmission development process
- MRTU

Mr. ISSA. Mr. Lynch,

STATEMENT OF MARK S. LYNCH

Mr. LYNCH. Thank you, Mr. Chairman.

My name is Mark Lynch; and I am president and chief executive officer of the New York Independent System Operator [NYISO].

The NYISO's mission is to ensure the reliable, safe and efficient operation of the State's major transmission system and to administer an open, competitive and nondiscriminatory wholesale market for electricity in New York State.

The fundamental importance of system reliability is highlighted in New York State as home to one of the world's most important financial and communication centers. After reviewing the FERC's Summer Assessment, we generally agree with the Office of Enforcement's findings as they pertain to New York and the potential risk to be addressed this summer.

It is important to note that New York has a long history of interregional coordination and mutual assistance with our neighboring control areas, which include ISO New England, PJM, and the Canadian provinces of Ontario and Quebec. These arrangements are fundamental to the overall reliability of the region and have proven very effective in allowing control area operators to manage system contingencies and respond to system emergencies.

New York State's generation resources currently meet all applicable standards, including the locational requirements that apply to New York City and Long Island. The outlook for both New York City and Long Island has improved for this summer as compared to last year, though high fuel cost and demand could still yield high prices there this summer. Long Island has benefited from the operation of its submarine cable interconnection with New England. Additional benefits will be achieved when the planned Neptune cable between PJM and New York is completed.

Notwithstanding an overall positive outlook for the summer, it is important to note that recent unplanned outages on two transmission cables into New York City occurred following the issuance of the Summer Assessment. These outages are expected to continue until early to mid-August and have added to the challenges of dealing with the summer demand in New York City.

The New York ISO has worked with Con Edison to implement plans to address the situation, and the city continues to meet all applicable reliability criteria. However, the possibility for voltage reductions or controlled, localized load shedding remains somewhat elevated under extreme weather conditions or in the event in the loss of additional facilities.

In addition to ensuring day-to-day reliability, the New York ISO is concerned with providing market signals to attract the infrastructure and investment needed to meet the future demand in electricity. In 2005, the NYISO conducted the first in a series of annual studies as part of its comprehensive reliability planning process. The first draft report recently issued by the NYISO identifies future reliability needs and finds that resources needed to address them are either planned or under development. The draft report also identifies issues and potential risks and provides an action plan to address those issues.

Of course, it is important to ask whether the wholesale electric markets in New York State support and encourage investment in new generation facilities where they are needed. The answer so far is a resounding yes.

The location-based approach to pricing energy and capacity provides detailed price signals about where additional generation is needed and the likely economic value of that generation. Nearly 5,000 megawatts of new capacity have been added to the system since NYISO began operation. Generator availability rates have improved by over 10 percent, which is largely the result of the NYISO's capacity market rules that reward high unit availability. In addition, the NYISO's demand-side programs, which include over 1,800 megawatts of resources, have been very successful.

Notwithstanding the success of the NYISO markets in sending economic signals to incent development, longstanding institutional barriers continue to impact the development of needed infrastructure. For example, New York State's generating siting law, referred to as "Article X," expired in 2003 and has not yet been replaced.

The longer-term reliability and economic needs cannot be met with new generation alone. Further growth of the NYISO's demand-side programs and improved transmission facilities are also very important to satisfying continued load growth.

While some transmission capacity has been added in recent years, overall investment in transmission in New York has been modest. The difficulty of licensing transmission has long been a challenging impediment to transmission investment. The backstop provisions provided by Congress included in last year's Energy Policy Act will help alleviate that uncertainty.

In conclusion, the paramount responsibility of the New York ISO is to ensure reliability of the New York State's bulk electric system. Since it began operation in 1999, the New York ISO has fulfilled this mission without compromise. The markets administered by the New York ISO have proven not only to be compatible with system reliability but, in fact, have enhanced system reliability in New York State by providing the price signals necessary to attract additional generating capacity, by providing financial incentives for generating units to maintain a high rate of unit availability, and by introducing innovative demand-side programs that increase reliability and market efficiency.

As we move forward to address the important challenges that I've touched upon today, I am confident in the New York ISO's ability to meet the reliability needs of New York State while administering fair and open and competitive markets.

Thank you.

Mr. ISSA. Thank you.

[The prepared statement of Mr. Lynch follows:]

UNITED STATES HOUSE OF REPRESENTATIVES
COMMITTEE ON GOVERNMENT REFORM
SUBCOMMITTEE ON ENERGY AND RESOURCES

Oversight Hearing: "Can the US Electric Grid Take Another Hot Summer?"

Testimony of Mark S. Lynch

President & CEO
New York Independent System Operator, Inc.

July 12, 2006

Introduction

Good afternoon, ladies and gentlemen. My name is Mark S. Lynch, and I am the President and Chief Executive Officer of the New York Independent System Operator, or the NYISO. I appreciate this opportunity to appear before the Subcommittee on Energy and Resources in connection with this hearing regarding the reliability of the US electric grid and the issues highlighted in the Federal Energy Regulatory Commission's "Summer Energy Market Assessment 2006," ("Summer Assessment") issued on May 18 of this year.

Immediately prior to coming to the NYISO, I was Vice President of the Atlanta-based Mirant Corporation where I served as President of Mirant New York and Mirant New England. My experience at Mirant included various aspects of electric generation and transmission. I also served as Vice President of Power Generation and Delivery for Mississippi Power Company, and Vice President of Southern Energy. Before becoming Vice President, I held domestic and international Project Director positions with Southern Energy. I am a graduate of Villanova University with a B.E.E. in Electrical Engineering.

NYISO Background

The NYISO is a not-for-profit organization formed in 1998 as part of the restructuring of New York State's electric power industry. Our mission is to ensure the reliable, safe, and efficient operation of the State's major transmission system and to administer an open, competitive, and nondiscriminatory wholesale market for electricity in New York State. In 2005, the NYISO administered over $11 billion in wholesale electric market transactions. As you know, we are pervasively regulated by the Federal Energy Regulatory Commission ("FERC"). As provided in the Federal Power Act, we are also regulated by the New York State Public Service Commission with respect to certain financings.

The fundamental importance of system reliability is highlighted in New York State as home to one of the world's most important financial and communication centers. Accordingly, it is appropriate for an inquiry into electric system reliability in New York State to focus in particular on the metropolitan area that includes New York City and Long Island, as the Summer Assessment does. Furthermore, given the long lead time required to develop generation and transmission resources, a clear understanding of the reliability concerns of New York requires consideration of both the near-term and longer-term issues confronted by the State.

On a related note, I would like to take this opportunity to express our gratitude for how quickly FERC, under Chairman Kelliher, has responded to the Energy Policy Act of 2005 and moved toward mandatory reliability rules for the electric utility industry.

2006 Summer Assessment

As you know, the Summer Assessment deals with those geographic areas and issues of particular interest to the FERC's Office of Enforcement for the summer of 2006. After reviewing the report, we generally agree with the Office of Enforcement's findings as they pertain to New York and the potential risks to be addressed this summer.

It is important to note that the NYISO and its predecessor in operating the New York State bulk electric system, the New York Power Pool, have a long history of interregional coordination and mutual assistance through operational coordination agreements with our neighboring control areas--which include ISO-NE, PJM, and the Canadian provinces of Ontario and Quebec. These agreements are fundamental to the overall reliability of the region and have proven very effective in allowing control area operators to manage system contingencies and respond promptly to system emergencies. By way of example, there were 11 instances between

2004 and 2006 in which the NYISO provided emergency assistance to a neighboring control area.

New York State's generation resources currently meet all applicable standards. These standards specify the amount of generating capacity that must be available to New York State. From these requirements, the NYISO also calculates locational requirements for the State's most transmission-constrained areas, New York City and Long Island. Sufficient generation resources exist in both of these locations to satisfy the locational requirements determined by the NYISO for summer of 2006.

In fact, the outlook for both New York City and Long Island is improved for this summer as compared to last year. As identified in the Summer Assessment, the recent addition of 1000MW of new generating capacity in New York City has helped to alleviate reliability and pricing concerns, though high fuel costs and high demand could still yield relatively high energy prices there this summer. Long Island has benefited from the operation of its submarine cable interconnection with New England, and we are grateful for the assistance of the US Department of Energy in facilitating the operation of that facility. Additional benefits will be achieved when the planned Neptune cable between PJM and New York is completed.

It is important to note that, notwithstanding an overall positive outlook for the summer, recent unplanned outages on two major subterranean transmission cables into New York City occurred following the issuance of the Summer Assessment. These outages, which are expected to continue until early to mid-August, have added to the challenges of dealing with summer demand in New York City. The NYISO has worked with Con Edison, the local utility that owns the cables, to implement plans to address this situation, including coordination with neighboring PJM to address various operating contingencies. The new generating capacity that has been brought online in New York City has been helpful in dealing with this situation and the city continues to meet all applicable reliability criteria. However, the possibility for voltage reductions or controlled, localized load shedding remains somewhat elevated under extreme weather or the loss of additional facilities.

Longer-Term Outlook

While responsibility for the reliable operation of the New York State bulk electric system is of primary importance on a day-to-day basis, the NYISO is equally concerned with providing the appropriate market signals to attract investment in energy infrastructure improvements needed to meet the future demand for electricity.

In addition to the operational coordination agreements noted above, the NYISO also has in place a number of standing agreements with neighboring control areas to address various longer-term issues such as inter-regional planning issues and so-called "market seams" issues. Significant progress has been made under these agreements in harmonizing market rules and practices, improving communications, and facilitating cross-border transactions which have improved both reliability and market efficiency throughout the Northeast.

In 2005, the NYISO conducted the first in a series of annual studies as part of its Comprehensive Reliability Planning Process. This is a collaborative and transparent process, involving all stakeholder sectors and open to all resources, including demand-side resources, to meet the future reliability needs of New York State. Through this Comprehensive Reliability Planning Process, the NYISO has developed a ten-year plan, to be updated annually, which addresses the long-term reliability needs of the New York State bulk power system. The first draft report recently issued by the NYISO identifies future reliability needs and finds that the resources needed to address them are either planned or under development. The draft report also identifies issues and potential risks and provides an action plan to address those issues.

Electric Markets and Reliability

Of course, an important question to be considered is whether the wholesale electric markets in New York State support and encourage investment in new generation facilities where they are needed most. While the NYISO-administered markets have only been in operation for a relatively short time, the answer so far is a resounding "yes."

The location-based approach to pricing energy and capacity in the NYISO markets provides detailed price signals about where additional generation is needed and the likely economic value of that generation. This has proven very effective in attracting developers proposing new generation projects in New York. Since the inception of the NYISO, there has been nearly 5000MW of new capacity added to the system, with the majority of that capacity located in the New York City/Long Island region.

Furthermore, the NYISO markets have proven to enhance system reliability beyond the addition of new generating capacity. Since the beginning of NYISO market operations, generator availability rates have improved by over 10%, which is mainly due to the application of the NYISO's capacity market rules that reward high unit availability. In addition, the NYISO's demand-side programs have been very successful, improving system reliability and helping to lower costs. The NYISO's various Demand Side Resource programs have grown over time to include over 1800MW of resources.

The New York electricity markets have been in operation for only six years, but one study of their effectiveness has already been published. The Staff of the New York State Public Service Commission recently released a Report on the State of Competitive Energy Markets in

New York. That Report was consistent with this testimony and found that the wholesale electric markets operated by the NYISO "are among the most advanced in the nation and that wholesale competition has led to significant efficiencies."

Other Reliability Considerations

Notwithstanding the success of the NYISO markets in sending economic signals to incent development, longstanding institutional barriers continue to impact the development of needed infrastructure.

New York State's generation siting law, referred to as "Article X," expired in 2003 and has not yet been replaced. This is an issue that urgently requires legislative action. Until the State Legislature acts to pass a new generation siting law, the State is dependent on the vagaries of local zoning for the licensing of facilities needed to secure the State's electricity supply.

But longer-term reliability and economic needs cannot be met through the addition of new generation alone. Further growth of the NYISO's demand-side management programs and improved transmission facilities are also very important to satisfying continued load growth. While nearly 1000MW of transmission capacity has been added, or is in the process of being added between New York and other control areas, in recent years overall investments in transmission have been modest.

Transmission affects many miles of urban, suburban, and rural real estate, and licensing it has long been a challenging impediment to transmission investment. The "backstop" provisions that Congress included in last year's Energy Policy Act will partially alleviate that particular uncertainty, but both federal and state regulators must also find ways to assure regulated investors of adequate returns if substantial transmission reinforcement is to take place. Merchant investment will depend, in part, on the ability of developers to obtain long term contracts from load serving entities, and regulators can help in that regard by encouraging regulated LSEs to enter into such contracts.

Conclusion

In conclusion, the paramount responsibility of the NYISO is assuring the reliability of the New York State bulk electric system. Since it began operations in 1999, the NYISO has fulfilled this mission without compromise. The markets administered by the NYISO have proven to be not only compatible with system reliability, but have in fact enhanced system reliability in New York State by providing the price signals necessary to attract additional generating capacity, by providing financial incentives for generating units to maintain a high rate of unit availability, and by introducing innovative demand-side programs that increased system reliability and market efficiency. As we move forward to address the important challenges that I have touched upon today, I am confident in the NYISO's ability to continue meeting the reliability needs of New York State while administering fair, open, and competitive electric markets.

I want to thank the members of the subcommittee for the opportunity to be here. I would be happy to answer any questions you may have.

# # #

HOUSE ENERGY & RESOURCE SUBCOMMITTEE
OVERSIGHT HEARING
JULY 12, 2006

ATTACHMENTS TO MARK LYNCH'S TESTIMONY

1. **NYISO History/Structure/Markets**
   (M. Lynch Presentation: New York Energy Bar Association, June 2005)

2. **NYISO Operating Agreements**
   http://www.nyiso.com/public/documents/regulatory/agreements.jsp
   a. **NYISO-PJM Inter-Control Area Agreement**
   b. **Interconnection Agreement between NYISO & HQ TE (Quebec)**
   c. **Interconnection Agreement between NYISO & IESO (Ontario)**
   d. **Interconnection Agreement between ISO-NE and NYISO**

3. **NYISO 2006 Summer Press Release (June 1, 2006)**

4. **NYISO 2006 Summer Readiness Review (4/19/06)**
   (Presentation)

5. **NYISO 2006 Summer Operating Study**
   http://nyiso.com/public/documents/studies reports/operating studies.jsp

6. **Northeast Power Coordinating Council Reliability Assessment for Summer 2006 (April 2006)**
   http://www.npcc.org/publicFiles/documents/seasonalNew/NPCC Reliability Assessment Summer 2006%20Final%20Report.pdf

7. **List of NYISO Coordination Agreements**

   a. **Northeast Independent Market Operators System Operation, Planning and Market Development Agreement (between NYISO, IMO & ISO-NE, effective date: June 11, 2002**
   b. **Interregional Coordination and issue Resolution Agreement (between NYISO & PJM, effective date: March 15, 2002**
   c. **Interregional Coordination and Seams Resolution Agreement (between NYISO and ISO-NE: effective date: July 31, 2003, revised February 2004)**
   d. **Northeastern ISO/RTO Planning Coordination Protocol (between NYISO, PJM and ISO-NE, effective date: December 2004)**

e. **Memorandum of Understanding on Coordination of Gas Supply Issues (between NYISO, PJM and ISO-NE, effective date: June 23, 2005)**

8. **Northeast ISO's Seams Resolution Report (NYISO, PJM and ISO-NE: April 2006)**
http://nyiso/com/public/webdocs/newsroom/current_issues/current_seams_projects.pdf

9. **NYISO Comprehensive Reliability Planning Process (July 13, 2005) (Presentation by John P. Buechler)**

10. **NYISO Comprehensive Reliability Plan (Draft, Issued June 30, 2006)**
http://nyiso.com/public/committees/documents.jsp?com=bic_espwg&directory=2006-07-10&cols=5&rows=5&start=1&maxDisplay=999

11. **New York ISO Perspective on Resource Adequacy**
(Presentation by Garry Brown: Northeast Power Markets Forum; March 30, 2006)

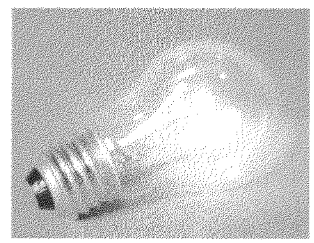
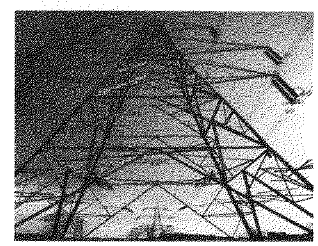
12. **NYISO Demand Response Programs**
Biannual Report Filed with FERC (June 2006)
http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2006/06/nyiso_cmplnc_dmnd_rspns_rprt_6_1_06.pdf

13. **Staff Report on the State of Competitive Energy Markets: Progress to Date and Future Opportunities (NYS Department of Public Service, Issued March 2, 2006)**
http://www.dps.state.ny.us/StaffReportCompetition.pdf

14. **White Paper: Value of Independent Regional Grid Operators (ISO/RTO Council; November 14, 2005)**
http://nyiso.com/public/webdocs/newsroom/press_releases/2005/isortowhitepaper_final11112005.pdf

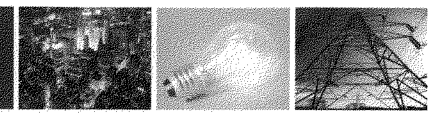
NEW YORK
INDEPENDENT
SYSTEM OPERATOR℠
Building the Energy Markets of Tomorrow . . . Today

NYISO Markets Update

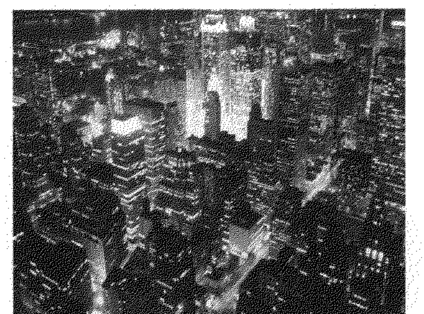
Mark S. Lynch
President & CEO
New York Independent System Operator

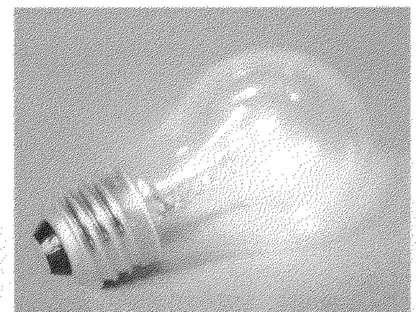
Energy Bar Association
June xx, 2005
New York City

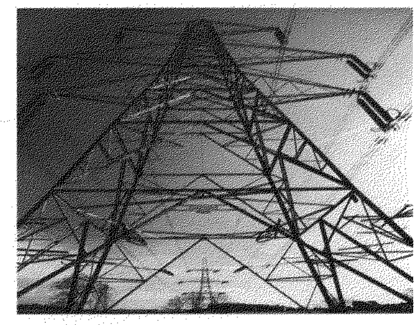


Outline

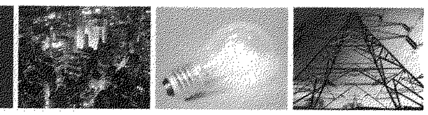
- What is the NYISO?
- NYISO Markets
- Recent Enhancements
  - ✓ *SMD2*
  - ✓ *Capacity Market*
  - ✓ *Demand Side Products*
  - ✓ *Comprehensive Planning Process*
- Future Challenges & Uncertainties
  - ✓ *Seams Resolution*
  - ✓ *Resource Adequacy*
  - ✓ *Regulatory Uncertainty*
  - ✓ *Security & Reliability*
- Closing Remarks





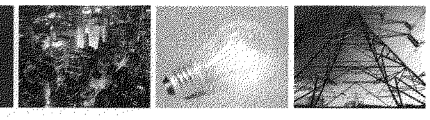


What is the New York Independent System Operator?



The NYISO's Primary Purpose

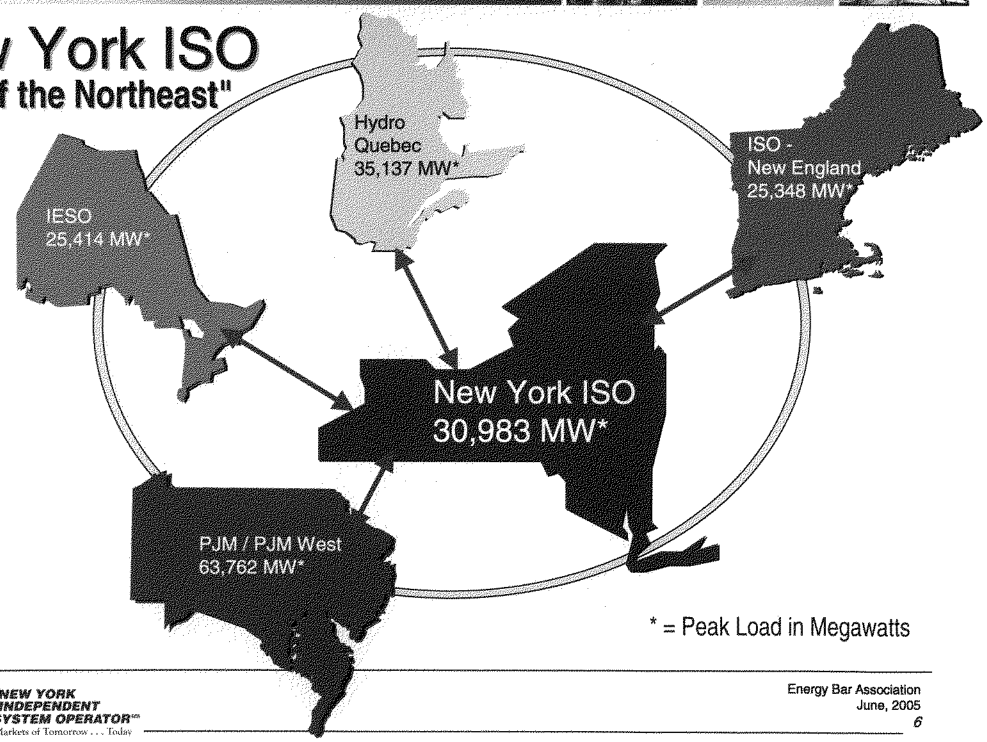
- Reliable operation of the New York bulk power system.
- Administering the competitive wholesale electricity markets.



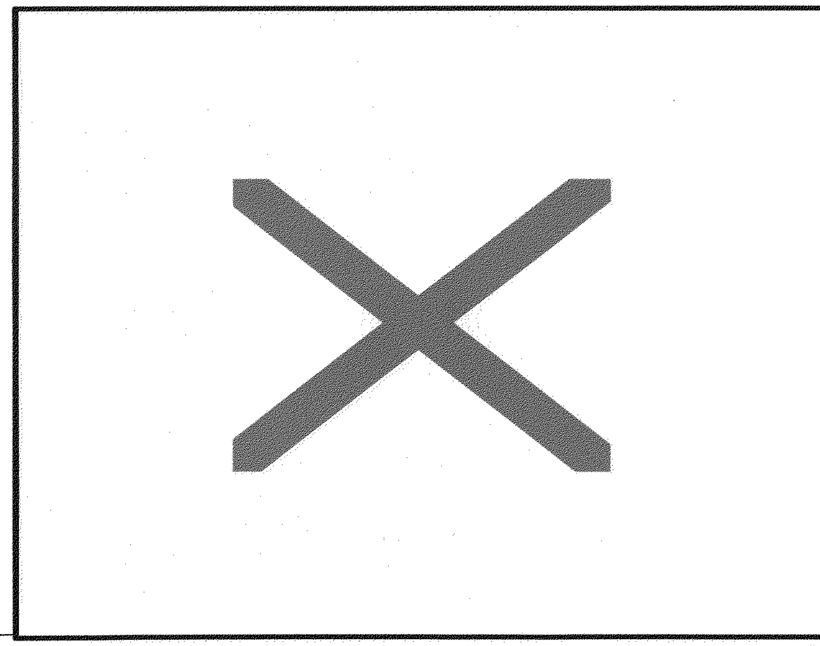
Background

- NYISO formed December 1, 1999.
- Independent Board and management
- Highly divested and complex marketplace featuring co-optimized market clearing systems.
- 91 percent utility generation divestiture rate makes it most divested market in nation.
- NYISO market volume was $7.3 billion last year and $30.4 billion since inception. Highest market volume in the East.
- Unique challenge: New York City is world's biggest and most complex load pocket. World capitals of finance and communications located within.
- Unique geography makes it the "Hub of the Northeast."

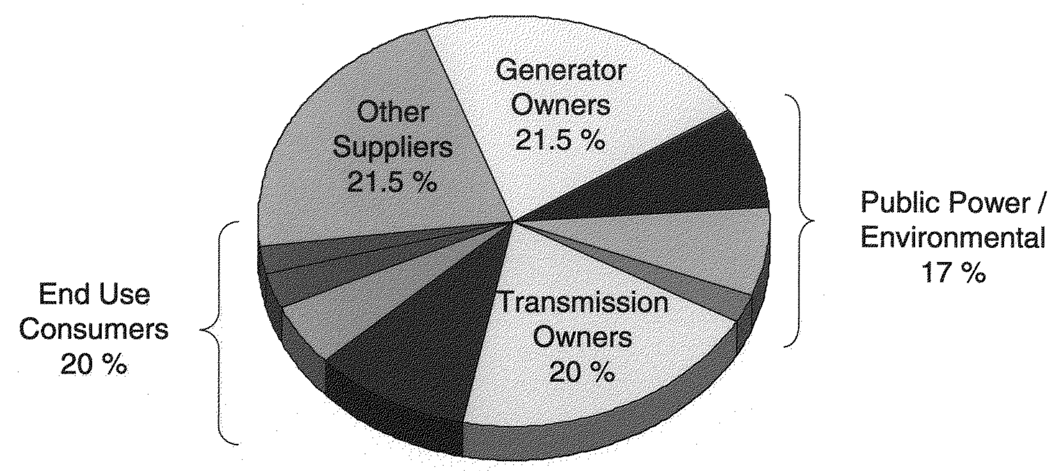
New York ISO
"Hub of the Northeast"

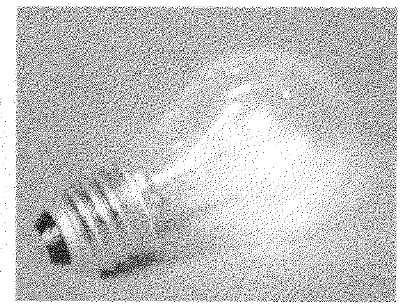


* = Peak Load in Megawatts

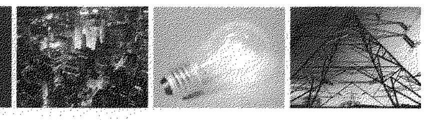


NYISO Stakeholder Representation



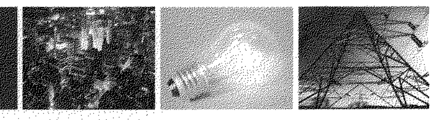




NYISO Markets Overview

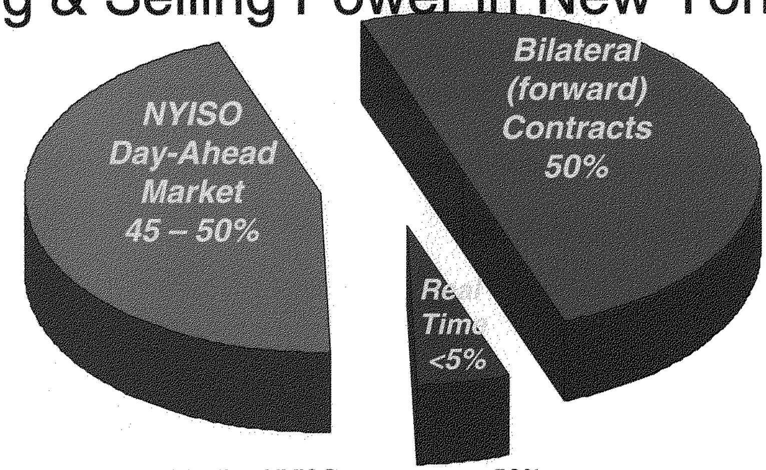


The NYISO - the Most Advanced Market

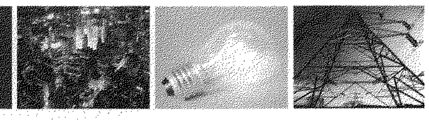
- NYISO Markets served as the model for FERC's SMD NOPR
- Two-Settlement System for Energy Markets
  - Day-Ahead
  - Real-time
- Additional Markets Administered by the NYISO
  - ✓ *Installed Capacity (ICAP)*
  - ✓ *Transmission Congestion Contracts (TCCs)*
  - ✓ *Reserves (10 min. spin, 10 min. non-spin, 30 min.)*
  - ✓ *Regulation*



Buying & Selling Power in New York

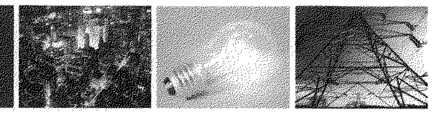


Bilateral Contracts outside the NYISO	*50%*
NYISO Day-Ahead Market	*45 - 50%*
NYISO Real-Time Market	*<u><5%</u>*
	100%



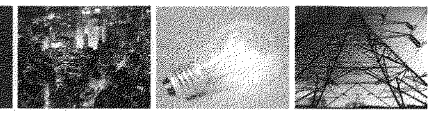
Market Design Characteristics

- Locational Marginal Pricing
  - ✓ *Locational nodal pricing for Energy and Reserves*
  - ✓ *Most efficient price to meet load requirements*
  - ✓ *Provides accurate price signals to guide efficient investment & siting decisions*
- Bid-Based Markets
  - ✓ *Co-optimized Energy, Regulation and Reserves*
  - ✓ *Multi-part bids (e.g. – start-up, min gen, energy)*
  - ✓ *Hourly variation in bids*
  - ✓ *Bilaterals & self-supply also accommodated*



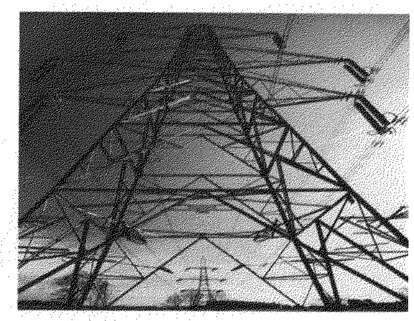
Market Design Characteristics (Cont'd)

- Transaction Scheduling Options
  - ✓ *Pre-scheduling – buy/sell service regardless of price*
  - ✓ *Economic – bid based clearing price*
- Financial Hedging Instruments
  - ✓ *Transmission Congestion Contracts*
  - ✓ *Contract For Differences*
  - ✓ *Virtual Trading*
- Demand Response
  - ✓ *Price Capped Load Bidding*
  - ✓ *Day-Ahead Demand Response Program*
  - ✓ *Emergency Demand Response Program*

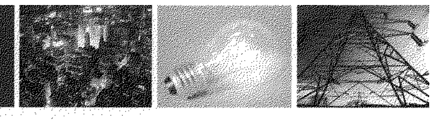


Ancillary Service Markets

- Market-Based Services
  - ✓ *Regulation*
  - ✓ *10-Minute Spinning Reserve*
  - ✓ *Total 10-Minute Reserve*
  - ✓ *30-Minute Reserve*
- Cost-Based Services
  - ✓ *Scheduling, Control and Dispatch*
  - ✓ *Voltage Support*
  - ✓ *Black Start*

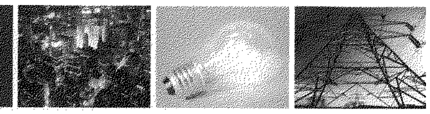


Recent Enhancements



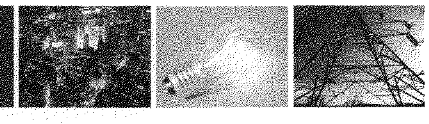
SMD2: Real Time Scheduling System

- Replacement for prior hourly balancing evaluation and 5-minute dispatch programs
  - ✓ *State-of-the-art system replaces 30-year old legacy system*
- Improved consistency between Day-Ahead and Real Time
  - ✓ *Scheduling and Pricing on the same platform and model*
- Real-time automated market power mitigation
- Demand Response – Increased capabilities to participate in RT Energy and Ancillary Service markets
- Provides significant benefits to overall efficiency of ancillary service markets



SMD2 (Cont'd)

- Implemented on February 1, 2005
- Two Settlement System for Reserves and Regulation
  - ✓ *Performance incentives embedded in settlement*
- Improved Pricing Signals
  - ✓ *Pricing recognizes scarcity conditions*
  - ✓ *Incorporates demand curves for reserves*
- More frequent scheduling and commitment
  - ✓ *Optimizes commitment & dispatch; reduces uplift costs*
  - ✓ *Reserve services will be scheduled and settled in 5-minute intervals as in real-time energy market*
  - ✓ *Evaluation every 15 minutes for commitment of quick-start resources*



Locational Capacity Markets

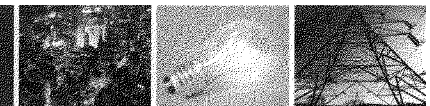
- Ensure resource adequacy to meet reliability requirements
- Statewide requirements are set by the NYSRC
- Locational requirements are set by NYISO
- LSEs meet their ICAP requirements with:
  - ✓ *Self-Supply*
  - ✓ *Bilateral Transactions with Suppliers*
  - ✓ *NYISO administered ICAP auctions*

Capacity Markets (Cont'd)

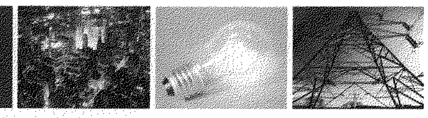
- NYISO market compatible with neighboring markets
  - ✓ *Permitting import and exports of capacity*
- Installed Capacity (ICAP) reflects historic availability (UCAP)
- Demand-side and Intermittent resources eligible
- A demand curve has been introduced to determine the prices for the deficiency/spot market:
  - ✓ *Increases reliability by valuing ICAP above the minimum requirements.*
  - ✓ *Reduces price volatility and sends a more stable revenue signal for new resources*
  - ✓ *Should help to retain existing facilities*

Leader in Demand Response

- NYISO is a leader among ISO/RTOs in market-based demand response programs
- Three principal programs:
  - ✓ *Emergency Demand Response Program (EDRP)*
  - ✓ *ICAP Special Case Resources (SCR)*
  - ✓ *Day Ahead Demand Response Program (DADRP)*
- These programs provide viable alternative solutions to generation & transmission

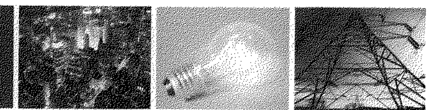


Feature	ICAP Special Case Resources (SCR) Program	Emergency Demand Response Program (EDRP)
Minimum resource size	100 kW, may aggregate within Zones	
Paid for	Capacity (kW) and Energy (kWh) Reduction	Energy (kWh) Reduction
Amount paid	Locational ICAP price, plus: Real-time market price or Strike Price (maximum $500/MWh), whichever is greater & guaranteed 4 hour minimum	Greater of real-time marginal price or $500/MWh & guaranteed 4 hour minimum
	May set real time market price under scarcity pricing rules	
Advance notice time	Provider advised 21 hours ahead with 2 hour in-day notification	Provider notified of activation 2 hours ahead, if possible
Who qualifies?	Interruptible load & emergency backup generation	
Program response	Mandatory - Resources Derated for Non-Compliance	Voluntary



Past EDRP/SCR Experience

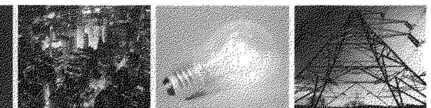
	Participants/ MW	Events	Load Curtailed	Payments
2001	292 712 MW	23 Hours Downstate 17 Hour Upstate	~425 MW	$4.2 Mil
2002	1711 1481 MW	22 Hours Downstate 10 Hour Upstate	~668 MW	$3.3 Mil
2003	1536 1708 MW	22 Hours Upstate and Downstate	~683 MW	$7.2 Mil



Market Impacts for EDRP/SCR

	EDRP Curtailed MWh	Collateral Savings ($M)	Reduced Hedge Cost ($M)	Reliability Benefits ($M)	Program Payments ($M)	Impact Ratio
2001	8,159	13.0	3.9	20.1	4.2	4.8
2002	6,632	0.5	0.3	4.8	3.3	1.5
2003						
EDRP	6,138	NA	NA	28.0	4.0	7.0
ICAP	6,576	NA	NA	26.3	3.3	8.0

- Prior to 2003, EDRP benefits did not distinguish between EDRP and ICAP/SCR program registration
- EDRP participants received $500/MWH: ICAP/SCR participants received higher of their bid, or LBMP



Market Price Impacts for DADRP

	Scheduled DADRP	Collateral Savings	Reduction in Hedge Cost	Program Payments
2001	2,694 MWh	$1.5 Mil.	$0.7 Mil.	$0.2 Mil.
2002	1,468 MWh	$0.2 Mil.	$0.2 Mil.	$0.1 Mil.
2003	1,752 MWh	$0.5 Mil.	$0.2 Mil.	$0.1 Mil.

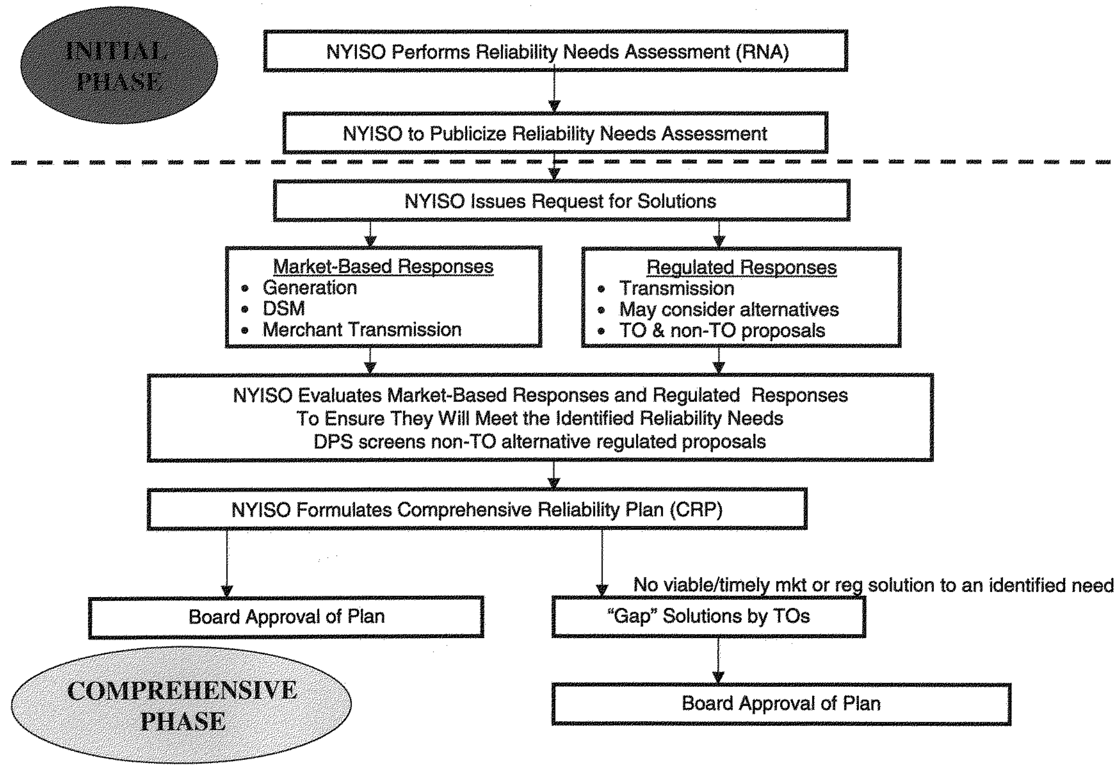
- Program costs and benefits are of similar orders of magnitude in all years but benefits clearly depend upon size of price responsiveness and scheduled curtailments

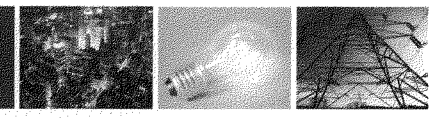
NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

NYISO Comprehensive Reliability Planning Process (“CRPP”)

- Approved by FERC on December 28, 2004
- Establishes a formal long-term (10-year) planning process for the NYISO
  - ✓ *Provides for both market-based & regulated backstop solutions*
  - ✓ *Open to all Market Participants and all resources*
  - ✓ *Defines roles of NYISO, FERC and NY PSC*
  - ✓ *Addresses cost allocation and cost recovery issues*
  - ✓ *NYISO-TO Agreement addresses TOs’ rights and obligations*
  - ✓ *Similar to ISO-NE and PJM RTEP for reliability needs*
- Meets NYISO Objective: To ensure that upgrades will be built when needed for reliability

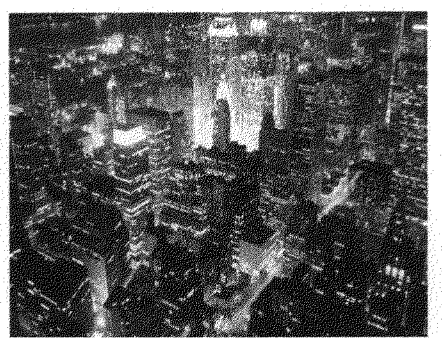
NYISO Reliability Planning Process



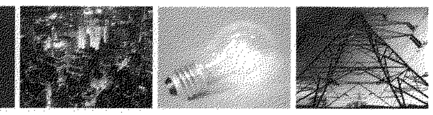


Economic Planning Process

- Analysis of historic congestion has not revealed any pressing need for "economic upgrades" in NY
  - ✓ *Bid Production Cost Impact = $85M (2003); $72M (2004)*
- Approved NYISO Economic Planning Process
  - ✓ *Expanded reporting of historic congestion*
  - ✓ *Focus on enhanced market-based initiatives*
  - ✓ *NYISO to perform estimates of future congestion*
  - ✓ *Market Participants evaluate opportunities/propose projects*
  - ✓ *NYISO to analyze proposed economic upgrades*
- Objective is to minimize regulatory intervention in the marketplace

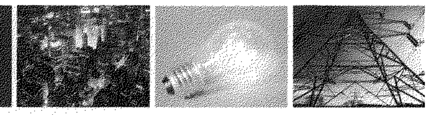


Future Challenges & Uncertainties



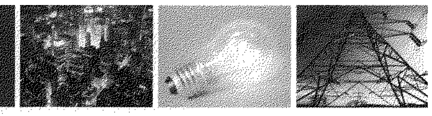
Seams Resolution

- A major barrier to inter-regional trade was removed on December 1, 2004 with the elimination of export fees between NYISO and ISO-NE
- NYISO's goal is to eliminate all rate pancaking charges with its neighbors
  - ✓ *PJM and Ontario next*
- NYISO and ISO-NE hope to achieve many of the benefits of a wider inter-regional dispatch through the introduction of an Interregional Transaction Scheduling system

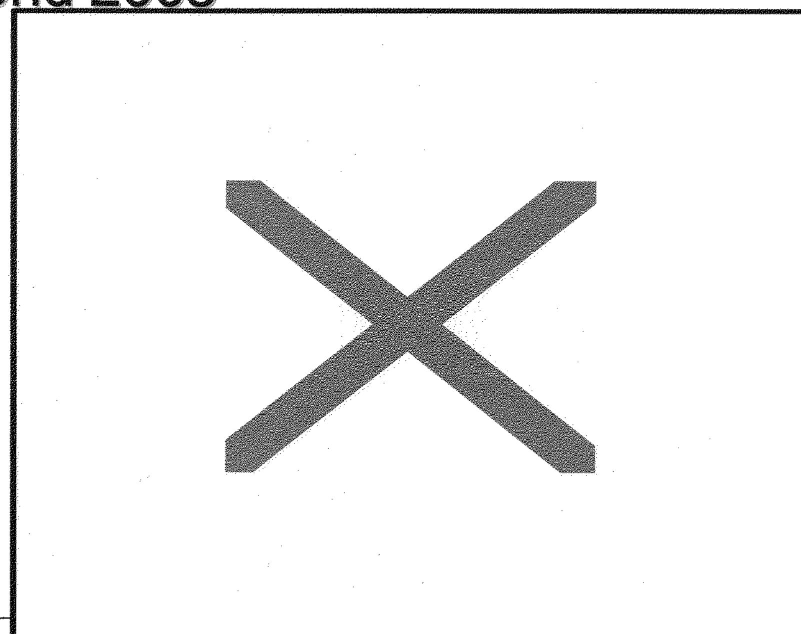


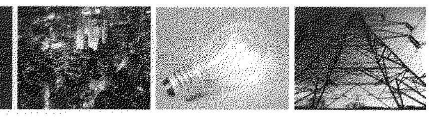
Resource Adequacy

- Upstate New York has sufficient supply in the near future
- NYC and Long Island require additional generation on an ongoing basis
- The New York law governing power plant siting, Article X, lapsed at the end of 2002 and the State Legislature should reenact it as soon as possible.



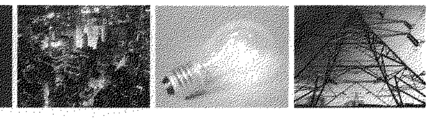
Beyond 2005





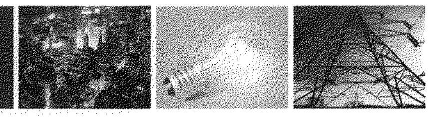
Regulatory Uncertainty

- Pat Wood's upcoming departure leaves doubt as to what the future direction of FERC will be
- Pending energy legislation may impose additional requirements for electric market operators
- ISO market monitoring & mitigation functions
  - ✓ *DC Circuit orders NY to shut off ROS AMP*
  - ✓ *FERC MMU Policy Statement & notice on reference prices*
- These developments may affect markets, which seek certainty and predictability



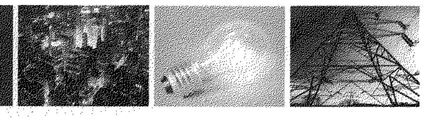
Security & Reliability

- Both physical & cyber-security concerns have produced unprecedented challenges for ISO/RTOs in protecting the grid from hi-tech intrusions that can interrupt reliability and market operation
- Almost two years after the August 14, 2003 Blackout, the Congress has failed to enact mandatory reliability legislation that could prevent future disruptions of service



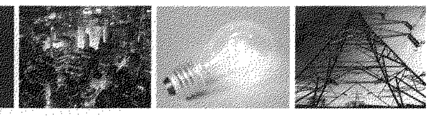
Closing Remarks

- The Northeast U.S. has led the way in establishing competitive wholesale electric markets
- Further refinements are still necessary (e.g. – seams resolution)
- The NYISO is committed to meeting the challenges that lie ahead



Visit our new website at:

www.nyiso.com



Questions??

NEWS RELEASE NEW YORK INDEPENDENT SYSTEM OPERATOR

Building The Energy Markets of Tomorrow . . . Today

For Immediate Release:
June 1, 2006

Contact:
Ken Klapp 518-356-6253
Jim Smith 518-356-8732

NYISO Releases Summer Electricity Forecast

A record for usage is anticipated, but supplies in New York will be adequate.

Rensselaer, N.Y. – The New York Independent System Operator (NYISO) expects New Yorkers to set a new peak for electricity usage this summer.

The NYISO, which is responsible for operating the state's bulk electric system and administering its wholesale electricity markets, released a peak load forecast of 33,295 megawatts (MW). If the record is achieved, it would be the first time since 1996 and 1997 that a new peak has been set in consecutive years. Last summer's load peaked at 32,075 MW on July 26, breaking a then week-old record of 31,741 MW.

New Yorkers should not be unduly alarmed, however. Because of the addition of new generation, the implementation of demand response programs and the availability of out-of-state capacity, New York City, Long Island and upstate should have adequate power supplies during the summer months.

"Economic growth, particularly in the southeastern portion of the state, coupled with increased air conditioning demands throughout the state, are helping to drive the summer peaks to these new levels," said Michael Calimano, the NYISO's Vice President, Operations. "Last summer's peak surpassed the 2001 record by nearly 1,100 MW and we are forecasting another 1,200 MW increase this summer."

Peaks are measurements of the average total electricity demand by consumers for a one-hour period. Generally, peak demand is reached in the late afternoon, regardless of the season. During a New York summer, usage climbs each day during a heat wave as tolerance for the heat wears thin. During these periods, and throughout the year, the NYISO works with power plants and transmission owners (utilities) to maintain reliable service to consumers.

While this forecast indicates there are sufficient supplies of electricity this summer, the NYISO continues to call on the state legislature to reinstate the Article X power plant siting law. Article X expired at the end of 2002, and according to the NYISO's 2005 Reliability Needs Assessment, the southeastern part of the state will need system reinforcements totaling 500 MW of capacity by 2008. Additionally, the region will need 1,250 MW of capacity by 2010 and 2,250 MW by 2015. These reinforcements could consist of new transmission, generation, demand side management, or a combination of the three.

"We strongly urge New York lawmakers to pass a power plant siting law to help avoid potential supply shortfalls in the future," said NYISO President and CEO Mark S. Lynch. "Supplies could start becoming very tight in less than two years."

In keeping with reliability rules and standards, the NYISO is required to maintain a year-round 18-percent reserve margin. It means that from May 1 through October of this year, 39,288 MW of installed capacity, including reserves, will have to be maintained. Installed capacity refers to the total amount of electrical power that generation plants commit to provide to New York State.

-more-

The NYISO expects that 38,169 MW of installed capacity will be available from in-state resources this summer. That number will increase to 43,487 MW with the addition of new generation, out-of-state supply and the capacity that demand response programs (in-state) provide.

For New York City, the installed "in-city" capacity required for May through October is 9,304 MW. With the addition of 500 MW of new generation, as well as capacity available from demand response programs, the total capacity will be 10,404 MW. Long Island has an "on-island" capacity requirement of 5,295 MW. It will have 5,732 MW of capacity available to meet it, according to the NYISO.

###

The New York Independent System Operator (NYISO) – www.nyiso.com – is a federally regulated, 501(c) 3 nonprofit corporation established in 1999 to facilitate the restructuring of New York's electric industry. The NYISO operates the state's high-voltage electric transmission system and administers the state's wholesale energy markets. The NYISO's market volume was $10.7 billion in 2005.

2006 Summer Readiness Review

4/19/2006

NEW YORK INDEPENDENT SYSTEM OPERATOR

NYCA Load and Capacity Outlook

For Summer 2006 (as of April, 2006)

New York Control Area	Summer
Forecast Demand	33,295 MW
Reserve Requirement	5,993 MW
Min.Total Requirement	39,288 MW
NYCA Available Supply[1]	38,727 MW
Need for New Units, External ICAP, or SCRs	561 MW

Potential Additional Supply	
New Units (see last page for listing)	830 MW
Special Case Resources	1,080 MW
External ICAP[2]	2,755 MW

1. Based on 2005 summer DMNC tests less 270 MW of firm sales. Includes new units of NYPA Poletti Expansion (476 MW) and Maple Ridge Wind Farm (190 MW) less Indeck Ilion Retirement (53 MW).
2. NYCA allows up to 2,755 MW of imports.

NEW YORK INDEPENDENT SYSTEM OPERATOR

New York City Load and Capacity Outlook

For Summer 2006 (as of April, 2006)

New York City	Summer
Forecast Demand	11,628 MW
In-City Requirements (80%)	9,302 MW
NYC Available Supply	9,502 MW

Potential Additional Supply	
New Units (see last page for listing)	500 MW
Special Case Resources	290 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR

Long Island Load and Capacity Outlook

For Summer 2006 (as of April, 2006)

Long Island	Summer
Forecast Demand	5,348 MW
On Island Requirements (99%)	5,295 MW
LI Available Supply	5,287 MW
Need for New Units or SCRs	8 MW

Potential Additional Supply	
New Units (see last page for listing)	330 MW
Special Case Resources	115 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR

NYCA Potential New Supply

Installed by July 1, 2006 (as of April, 2006)

Generator	Location	Rating
SCS Astoria	NYC	500 MW
Cross Sound Controllable Line[1]	LI	330 MW
TOTAL		830 MW

1. The Unforced capacity Deliverability Rights (UDRs) have been issued to LIPA for this line.

NEW YORK INDEPENDENT SYSTEM OPERATOR

NEW YORK
INDEPENDENT
SYSTEM OPERATOR

NYISO'S COMPREHENSIVE RELIABILITY PLANNING PROCESS

By

John P. Buechler

NYISO Executive Regulatory Policy Advisor

July 13, 2005

NYISO's Approach to Planning

- **NYISO historically performed short-term planning**
- **NYISO has employed a phased approach to the development of a Comprehensive Planning Process**
  - *Phase I: To address reliability needs first*
  - *Phase II: To address economic considerations*
- **Anchored in NYISO's market-based philosophy**
- **Dedicated stakeholder group was established in June 2003 (ESPWG)**
- **Active participation by market participants and NYPSC Staff throughout this process**

NYISO's Market-Based Philosophy

- NYISO is a strong believer in the power of markets and strives to achieve market-based solutions whenever possible
- This philosophy is supported by the NY PSC and other stakeholders and market participants
- The NYISO has a history of collaboration with its stakeholders and has successfully achieved consensus solutions with broad support
- The NYISO's markets (energy, Ancillary Services, congestion & capacity) support a reliable electric system
- LMP pricing signals provide the benefits of competition while achieving the intended results (e.g.– majority of new generation & Merchant Transmission have been proposed for the Southeast NY region where prices are high)

Stakeholder Process: A Delicate Balance

- **NYISO's Comprehensive Reliability Planning Process is the result of more than a year's intensive efforts**
- **A compromise was forged to meet the interests of many diverse groups**
  - *Generators and Marketers, LSE's & consumers, TO's, Public Power and Environmental, regulatory authorities & NYISO*
- **Resulting in the establishment of a Comprehensive Reliability Planning Process for New York that ensures reliability needs will be met**

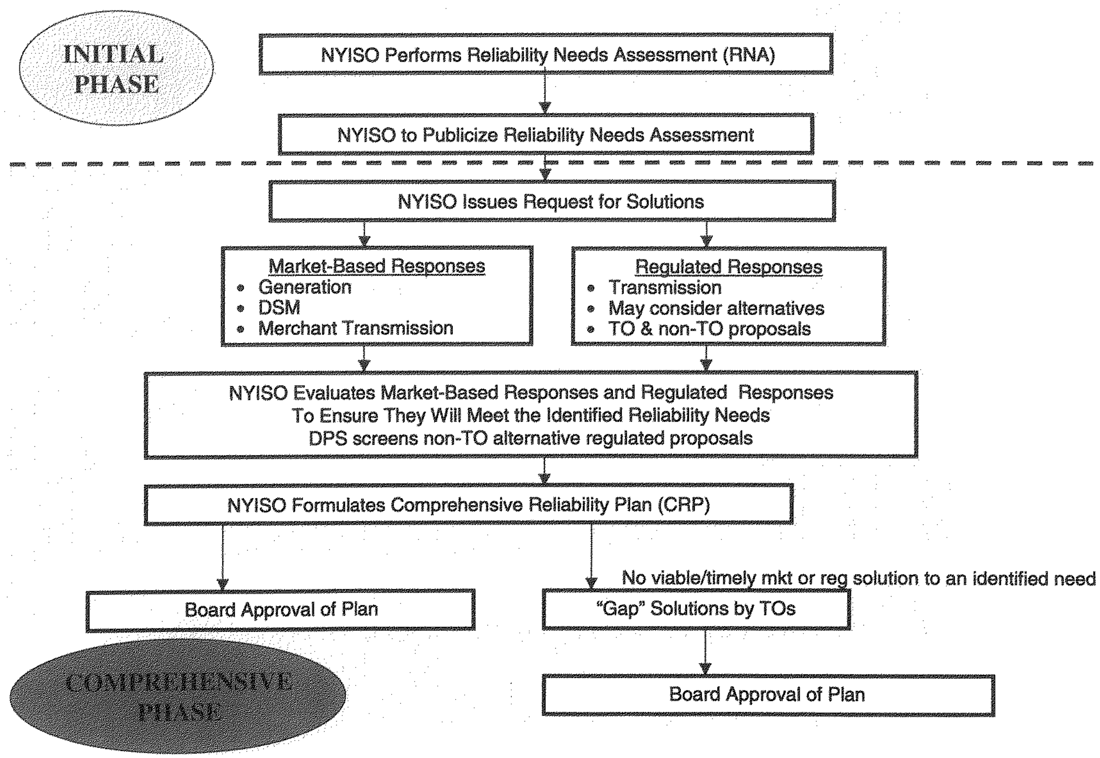
Phase I: Reliability Needs (CRPP)

- **Established a Comprehensive Planning Process for the identification and resolution of reliability needs that was approved by FERC on December 28, 2005**
- **The proposal included a methodology for the analysis and reporting of historic congestion costs**
- **FERC found the NYISO CRPP:**
  - *to "properly balance" consideration of market-based and regulated solutions; and that*
  - *"It is certainly a substantial improvement over planning processes that have traditionally depended upon TO developed regulated solutions."*

NYISO Comprehensive Reliability Planning Process

- **Establishes a formal long-term (10-year) planning process for the NYISO**
  - *Provides for both market-based & regulated backstop solutions*
  - *Addresses roles of NYISO, FERC and NY PSC*
  - *Addresses cost allocation and cost recovery issues*
  - *Provides a commitment to investigate cause of potential market failure and to modify market rules as needed*
  - *NYISO-TO Agreement addresses TOs' rights and obligations under CRPP*
- **Meets NYISO Objective: To ensure that upgrades will be built when needed for reliability**

NYISO Reliability Planning Process



Reliability Needs Assessment ("RNA")

- **NYISO Staff will perform a Reliability Needs Assessment over the 10-year planning horizon based upon existing reliability criteria**
- **Scenario analysis will be employed to test the robustness of the base case assumptions**
- **RNA will identify violations of reliability criteria, but will not identify specific facilities to meet the identified needs**
- **Provision for MP input & review of RNA**
  - *Through ESPWG & TPAS*
- **Provision for coordination with adjacent regions**
- **The final approved Needs Assessment will be widely distributed**

Request for Solutions

- **Following issuance of its RNA, the NYISO will provide an appropriate time period for the development of market-based & regulated responses**
- **Process is open to all resources**
- **NOT a formal "RFP" process**
- **When a Reliability Need is first identified by the NYISO:**
  - *TOs have obligation to prepare a regulated backstop proposal*
  - *Such proposals are not limited to transmission*
  - *Development time for the regulated backstop provides the benchmark for the lead time for non-TO alternate proposals*

Request For Solutions (Cont'd)

- **Market-based proposals are prepared in parallel with regulated backstop proposals**
  - *All resources are eligible: generation, merchant transmission, demand response*
- **Non-TO's may submit alternative regulated proposals to the NYDPS for consideration**
  - *Such proposals which satisfy the DPS may be submitted to the NYISO for evaluation*

NYISO Evaluation Process

- **NYISO will evaluate all proposals to determine if they will meet the identified reliability needs**
- **Regulated backstop proposals by TOs will establish the lead time for non-TO proposals**
- **If Market–based proposals are judged sufficient to meet the identified needs in a timely manner, the Comprehensive Reliability Plan ("CRP") will so state**
  - *NYISO will not select from among the market-based responses*
  - *NYISO will monitor status of market-based projects to ensure needs will continue to be met as part of its annual update process*

NYISO Evaluation Process (Cont'd)

- **If Market proposals are judged insufficient, NYISO will indicate that a regulated solution is needed in the CRP**
- **NYISO will evaluate non-TO regulated alternatives to determine whether they will meet the identified need, and will report its evaluation in the CRP**
- **If market-based proposals are not forthcoming**
  - *NYISO and its Independent Market Advisor will investigate whether that is due to market failure in one of its markets*
  - *If so, NYISO and its IMA will examine appropriate modifications to its market rules with MPs.*

CRP Review and Approval Process

- **NYISO staff issues draft CRP including designated regulated backstop solutions, if needed, to meet identified reliability needs**
- **NYISO Staff draft CRP is circulated for stakeholder review and comment**
- **NYISO staff makes revisions as appropriate**
- **Final draft CRP is sent to the appropriate stakeholder committees for review and vote**
- **NYISO staff makes revisions as appropriate**
- **Final draft CRP sent to Board for approval**
  - *Provision for remand to Management Committee*
  - *NYISO Board to have final approval of CRP*
- **CRP provided to regulatory agencies for their consideration**

"Gap" Solutions for Reliability Needs

- **If neither market proposals nor regulated proposals can satisfy the need in a timely manner, the NYISO may seek a "Gap" solution**
  - *NYISO may seek a gap solution outside of the normal Planning Process if there is an imminent threat to reliability*
  - *NYISO will not contract directly for gap resources*
- **TOs assume the obligation to immediately propose a "gap solution" for consideration by the NYISO and DPS**
- **To the extent possible, the gap solution should be temporary and strive to ensure that market based solutions will not be economically harmed**
- **A permanent regulated solution, if appropriate, may proceed in parallel with gap measures**

Cost Allocation and Cost Recovery

- **Cost Allocation for Regulated Projects**
  - *Based upon a "beneficiaries pay" principle*
  - *Specific methodology to be developed by NYISO/ESPWG*
  - *Near-term reliability needs are not anticipated based upon Phase I needs assessment*
- **Cost Recovery for Regulated Projects**
  - *Transmission solutions*
    - TOs to file for recovery with FERC
    - Recovery proposed through a separate rate schedule under the NYISO Tariff
  - *Non-transmission solutions*
    - In accordance with NYS Public Service Law

NYISO-TO Agreement

- **Defines TO rights and obligations with respect to the Comprehensive Reliability Planning Process**
  - *Similar provisions to those recently approved for RTO-NE*
- **TOs assume obligation to provide backstop regulated solutions**
  - *If NYISO determines that there are no viable market-based solutions which will meet identified Reliability Needs*
  - *Subject to cost recovery, permitting and other conditions*
- **Supplements existing NYISO/TO Agreement**
  - *Not subject to OC/MC approval*
- **Filed for FERC approval with NYISO Tariff Filing**

Role of the NYS PSC

- Reviews and screens "regulated alternatives" proposed by non-TOs
- Reviews and screens "gap" solutions
- Adjudicates disputes relating to reliability determinations in final RNA and in CRP
- Reviews TOs' backstop solution when NYISO determines action is necessary to ensure reliability
- PSC has final authority with respect to solution ultimately implemented
- PSC participation in the NYISO process will facilitate necessary approvals to ensure reliability

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Northeast Power Markets Forum

"New York ISO Perspective on Resource Adequacy"

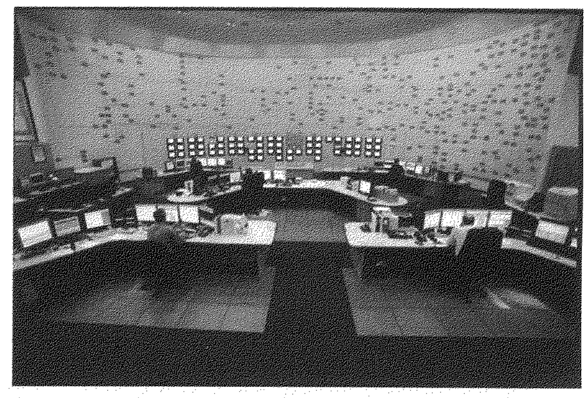
Thursday, March 30, 2006

Garry Brown
Vice President, External Affairs

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

The NYISO's Primary Purposes

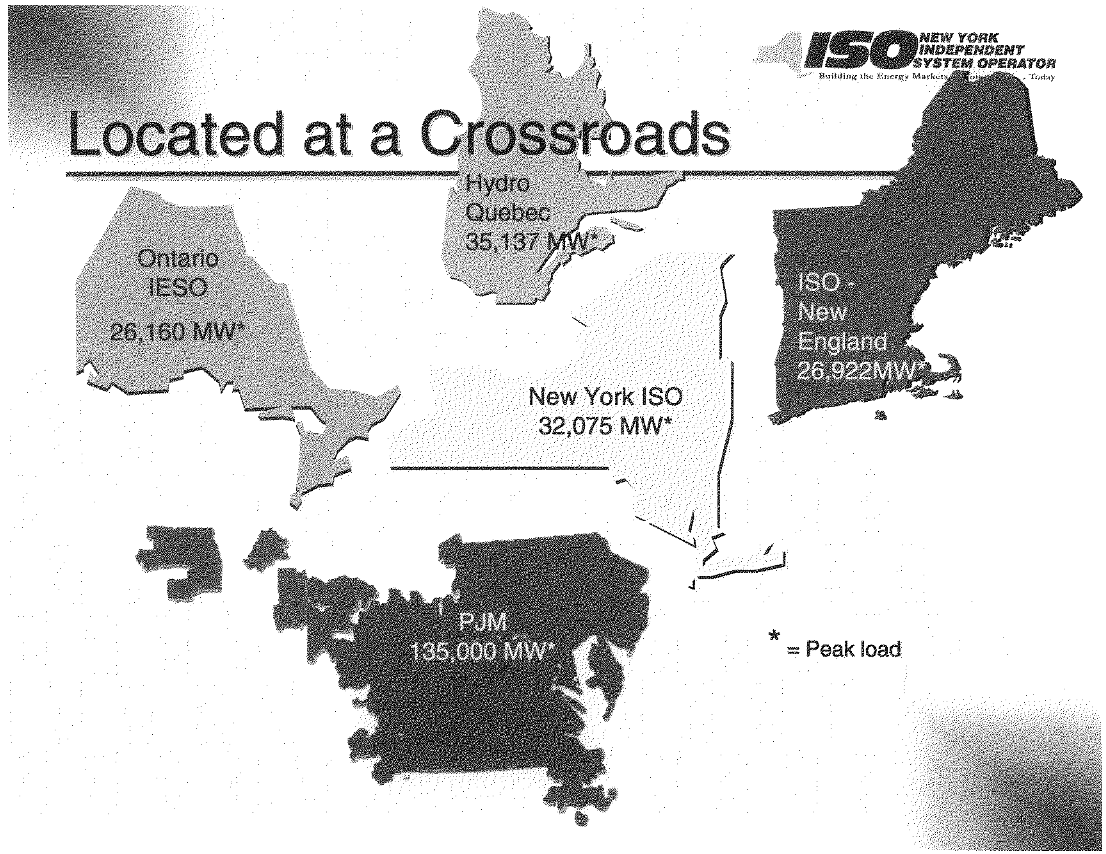
- Reliable Operation of the New York Bulk Power System
- Administration of the Competitive Wholesale Electricity Markets



NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Background

- NYISO formed December 1, 1999
- Independent board and management
- Highly divested and complex marketplace featuring co-optimization market clearing systems
- Most of the State's generation is independently owned
- NYISO market volume was $10.7 billion last year and $41.1 billion since inception
- Unique challenge: New York City is world's biggest and most complex load pocket


Located at a Crossroads
NEW YORK INDEPENDENT SYSTEM OPERATOR
Ontario
IESO
26,160 MW*
Hydro
Quebec
35,137 MW*
ISO -
New
England
26,922MW*
New York ISO
32,075 MW*
PJM
135,000 MW*
* = Peak load

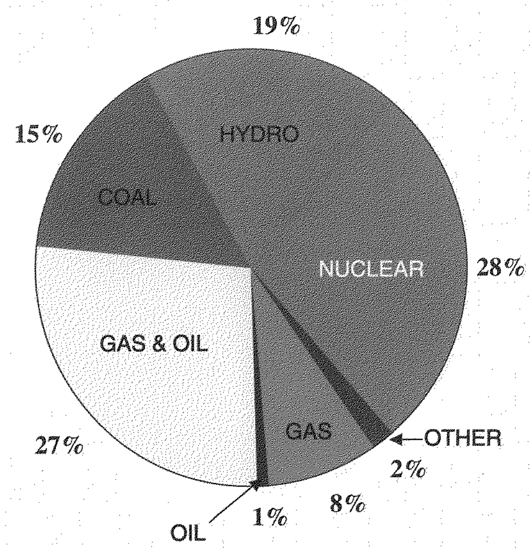
NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Control Area

- 19.2 million people
- Serving New York City
- 2005 load of 167,239 GWH
- Record peak of 32,075 MW (7/26/05)
- 10,775 miles of high voltage transmission
- Over 335 generating units modeled
- 2006 required Installed Capacity 39,288 MW

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

New York Energy by Fuel Type 2004



GWh

- GAS - 12387
- OIL - 939
- GAS & OIL - 40087
- COAL - 22536
- HYDRO - 28153
- NUCLEAR - 40626
- OTHER - 2443

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Historic Peak Loads

Year	Peak Load
1996	25,587 MW
1997	28,700 MW
1998	28,166 MW
1999	30,311 MW
2000	28,136 MW
2001	30,983 MW
2002	30,664 MW
2003	30,333 MW
2004	28,433 MW
2005	32,075 MW
2006	33,295 MW (forecast)

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Maintaining Resource Adequacy

- Proper Market Signals
- Capacity Markets
- Comprehensive Planning Process
- Regional Compatibility

New York State Reliability Council Installed Capacity Requirement (ICAP)

Required Installed Reserve Margin is
18% Above Forecasted Peak Load

(1 in 10 yrs major interruption criteria)

33,295 MW (2006 Forecasted Peak Load)
x 1.18

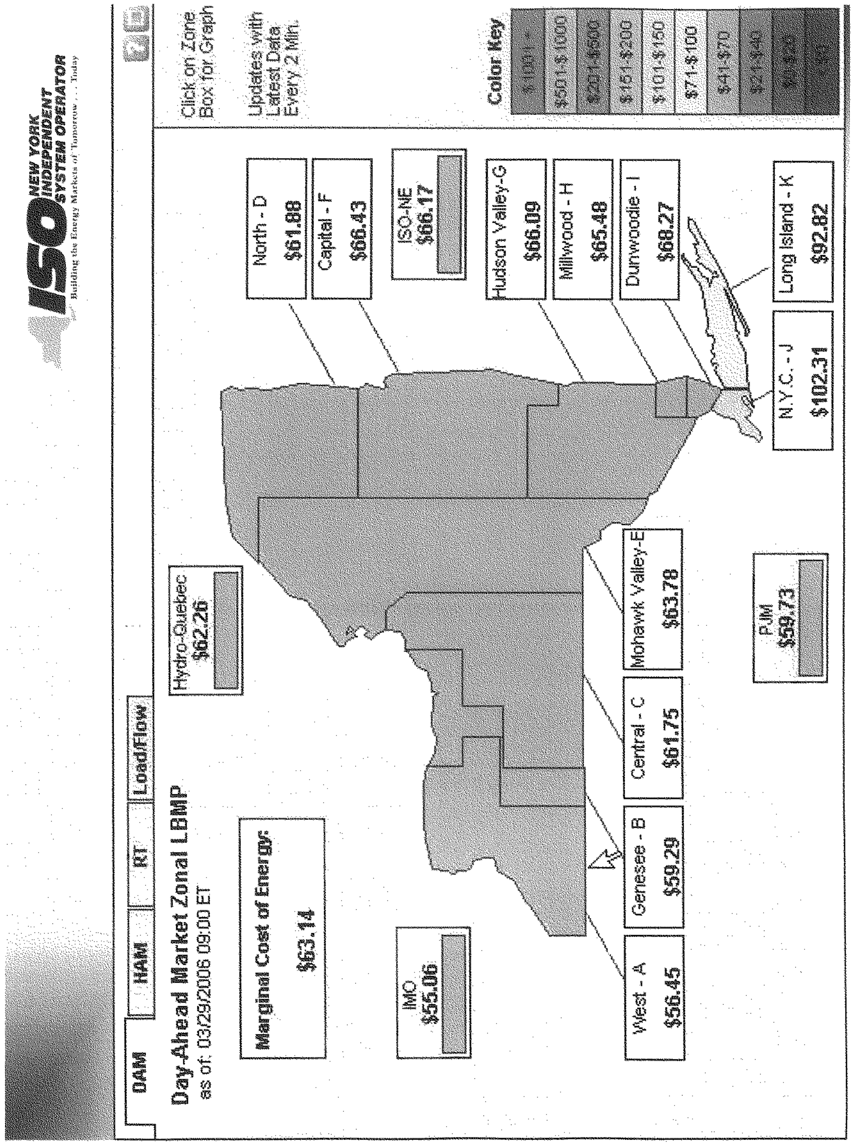
39,288 MW (NYISO ICAP Requirement)

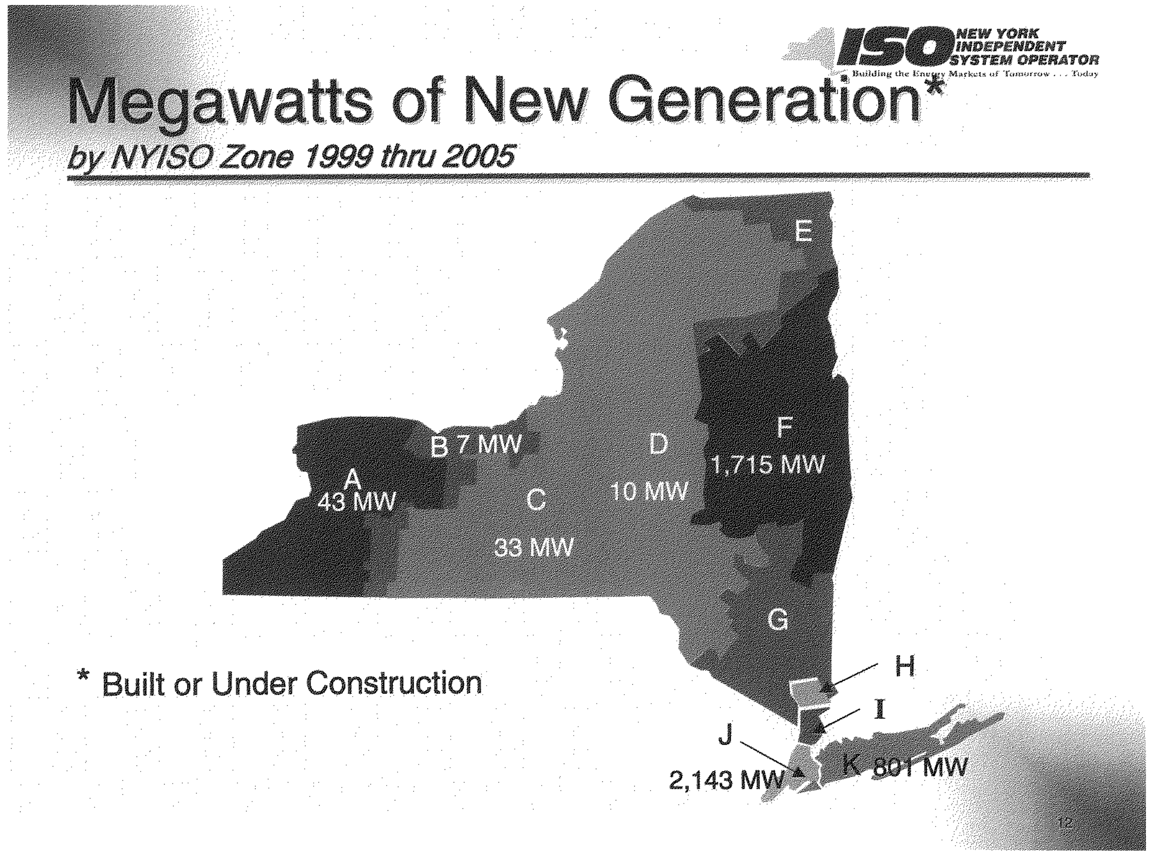
9

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

NYISO Market Based Philosophy

- Rely on market forces rather than centralized planning
- Successes
  - *New generation added in southeastern New York*
  - *New Transmission*
    - Cross Sound Cable
    - Neptune
    - Con Ed system additions and upgrades

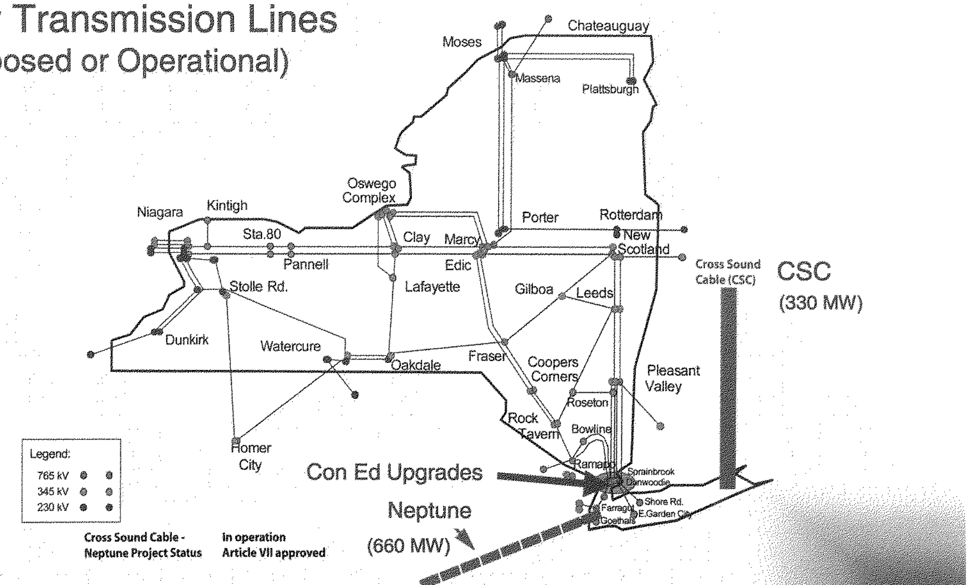

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today
DAM
HAM
RT
Load/Flow
Day-Ahead Market Zonal LBMP
as of: 03/29/2006 09:00 ET
Marginal Cost of Energy:
$63.14
IMO
$55.06
Hydro-Quebec
$62.26
West - A
$56.45
Genesee - B
$59.29
Central - C
$61.75
Mohawk Valley-E
$63.78
PJM
$59.73
North - D
$61.88
Capital - F
$66.43
ISO-NE
$66.17
Hudson Valley-G
$66.09
Millwood - H
$65.48
Dunwoodie - I
$68.27
N.Y.C. - J
$102.31
Long Island - K
$92.82
Click on Zone Box for Graph
Updates with Latest Data Every 2 Min.
Color Key
$1001 +
$501-$1000
$201-$500
$151-$200
$101-$150
$71-$100
$41-$70
$21-$40
$0-$20
$0


NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today
Megawatts of New Generation*
by NYISO Zone 1999 thru 2005
A 43 MW
B 7 MW
C 33 MW
D 10 MW
E
F 1,715 MW
G
H
I
J 2,143 MW
K 801 MW
* Built or Under Construction
12

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Transmission

New Transmission Lines
(Proposed or Operational)



NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

ICAP Markets in New York

- ICAP Requirements are set for the upcoming capability year.
- Load serving entities can meet their ICAP requirements by:
  - *Self-Supply*
  - *Bilateral Transactions with Suppliers*
  - *Forward Auctions*
  - *Deficiency/Spot Market Auctions*
  - *After-the-fact penalty procurement*

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Locational ICAP

- Due to transmission constraints into certain localities, areas or zones, some LSE's must procure at least some of their ICAP requirements from resources electrically located within that locality.
  - *New York (NY) has had locational requirements since inception. There are two such transmission constrained zones:*
    - New York City and
    - Long Island

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Demand Curve - NYISO Objectives

- Improve the traditional ICAP market.
- Increase system reliability by valuing additional ICAP above the NYCA and Locational Requirements.
- Reduce price volatility and send a more stable revenue signal for new resources
- Continue to ensure a competitive, fair, and non-discriminatory market for capacity in the NYCA.

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Demand Curve Spot Market Auction

- Replaced previous Deficiency Auctions.
- Uses a Demand Curve as a proxy for LSE Bids.
- The Demand Curves are based on the cost of new entry, with decreasing prices for ICAP above the NYCA or Locational Requirements.
  - *Conversely, the Demand Curve increases prices/value for ICAP when resources are short of the NYCA or Locational Requirements*
- Resources have the opportunity to supply ICAP above the NYCA and/or Locational ICAP Requirements.
  - *Reduces stranded capacity.*

NYISO's Comprehensive Reliability Planning Process

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

- For reliability needs – ten year planning horizon
- All sources eligible
  - *Generation*
  - *Transmission*
  - *DSM alternatives*
- Market based preference
- Regulatory backstop
- "Gap" solution
- NYISO identifies and evaluates proposed solutions to meet reliability needs
- "Best" solution evaluated in regulatory forum
- NYISO does not evaluate relative economics

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

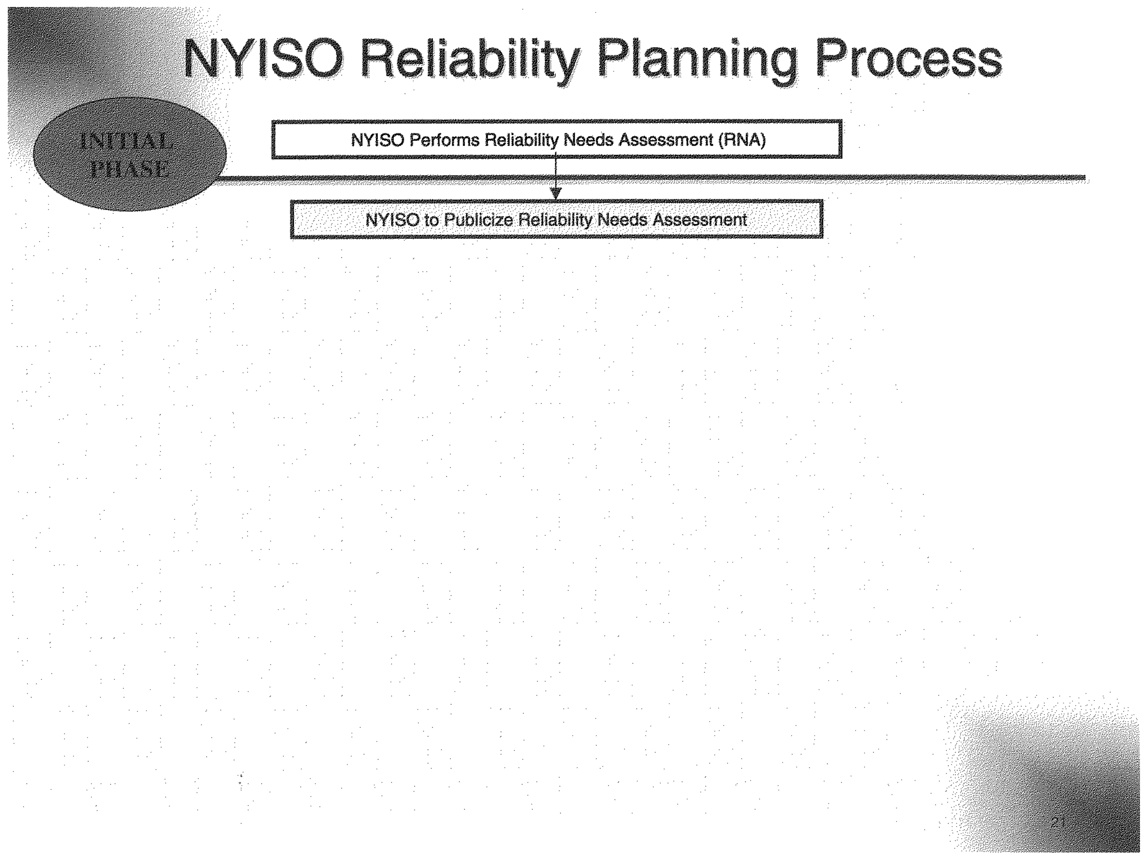
Base Case – Key Assumptions

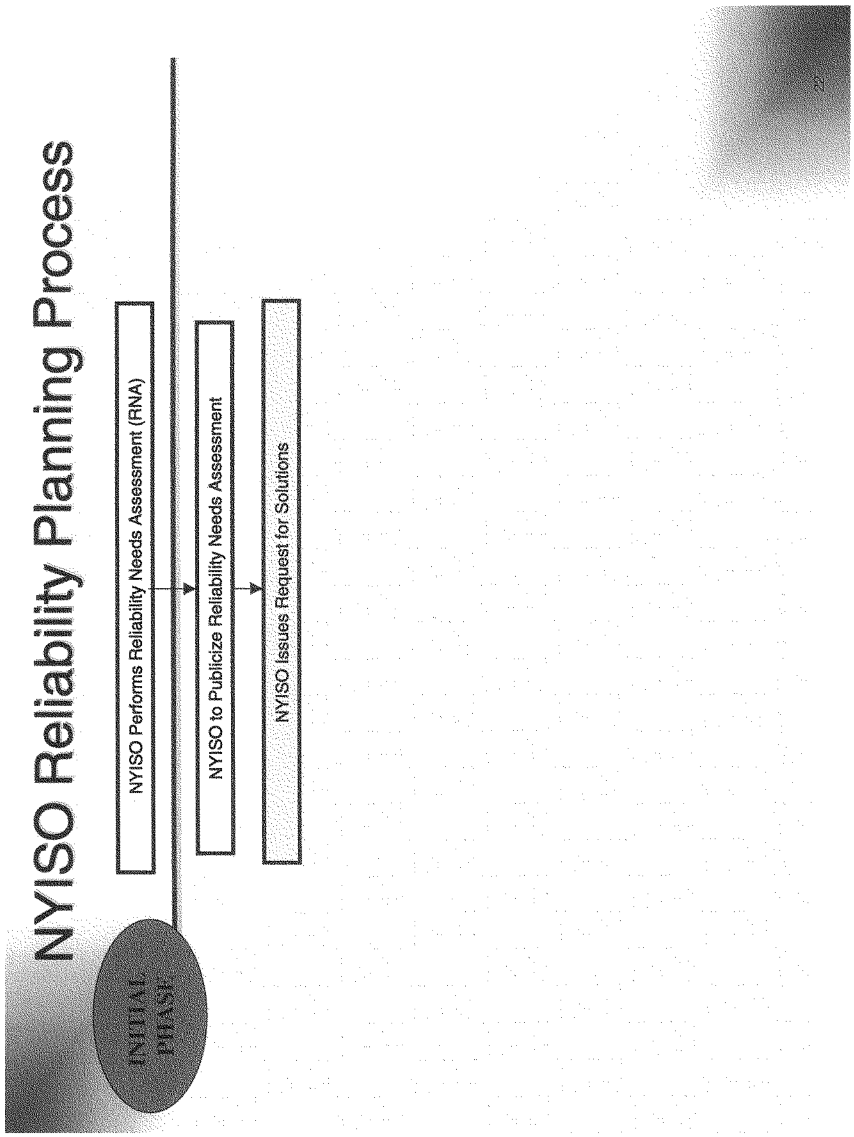
- Installed capacity (ICAP) requirement at 18% (interruption 1 time in 10 years)
- Load growth
- Generator retirements
- Generator additions
- Transmission expansion
- Import transactions

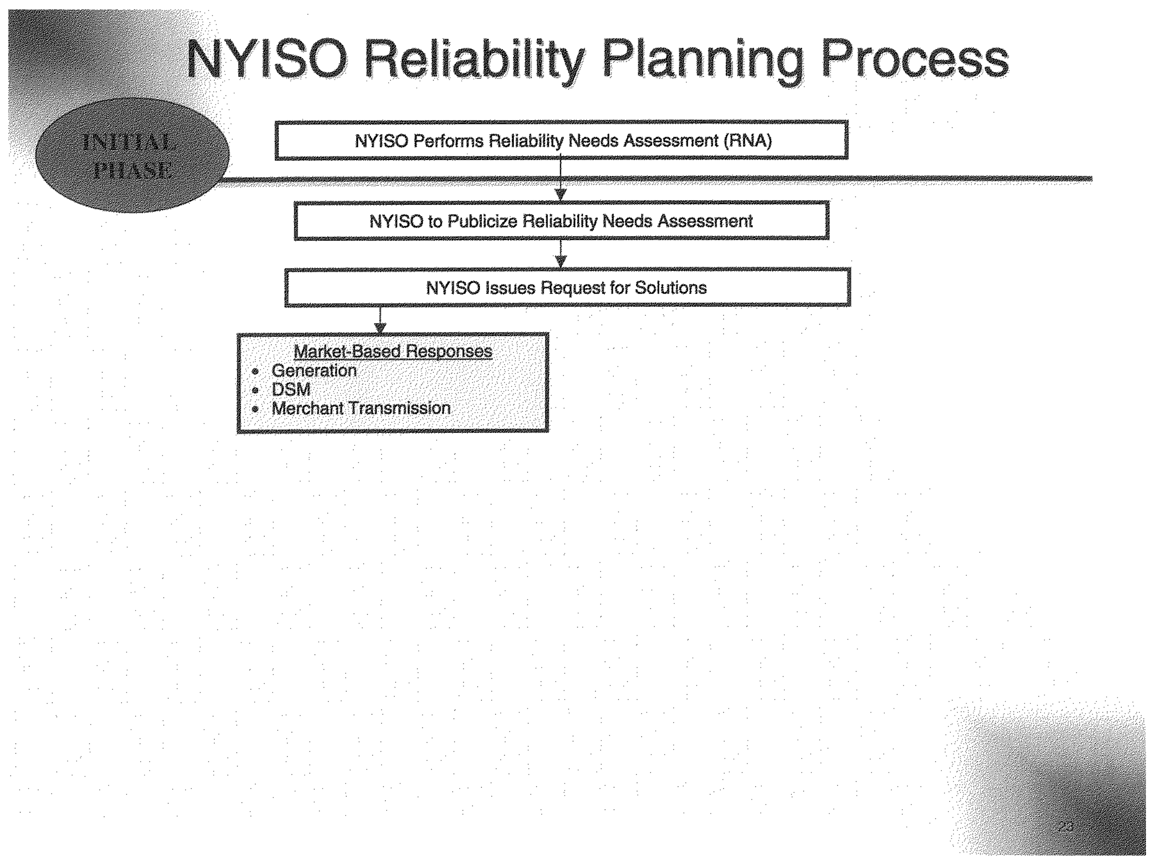
NYISO Reliability Planning Process

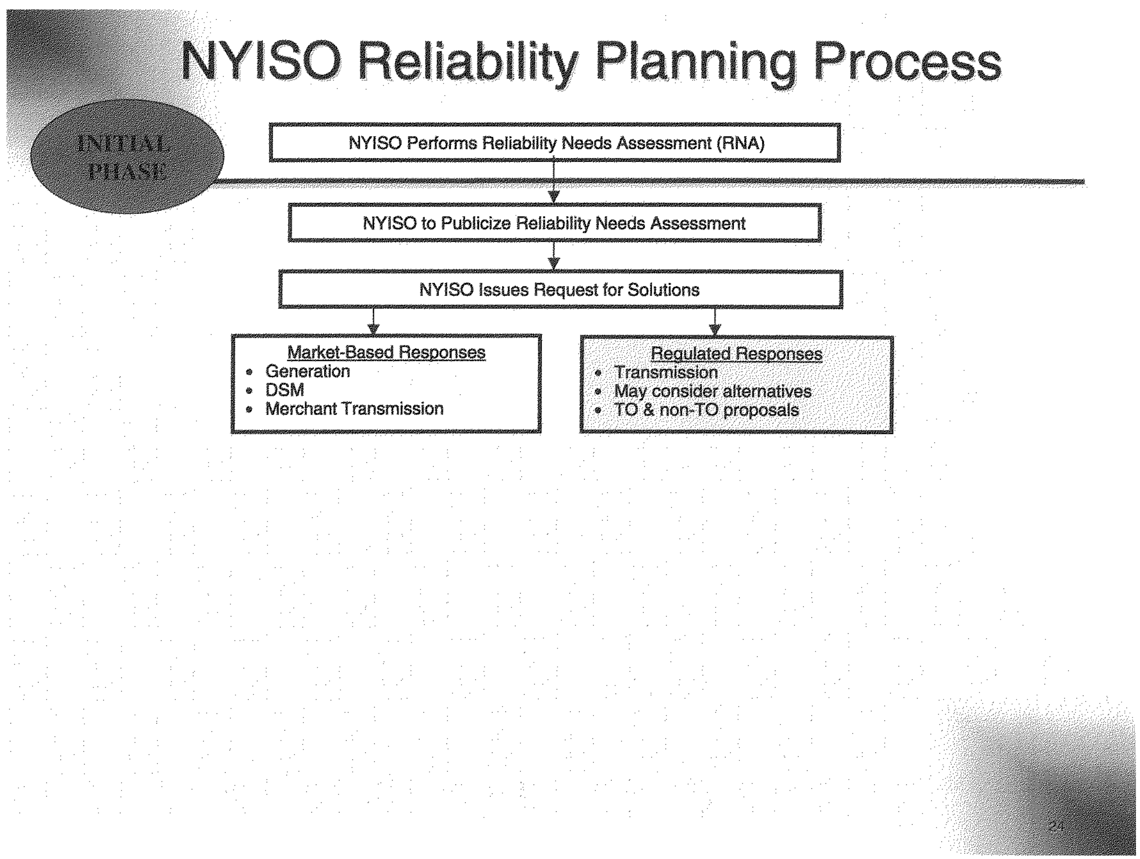
INITIAL PHASE

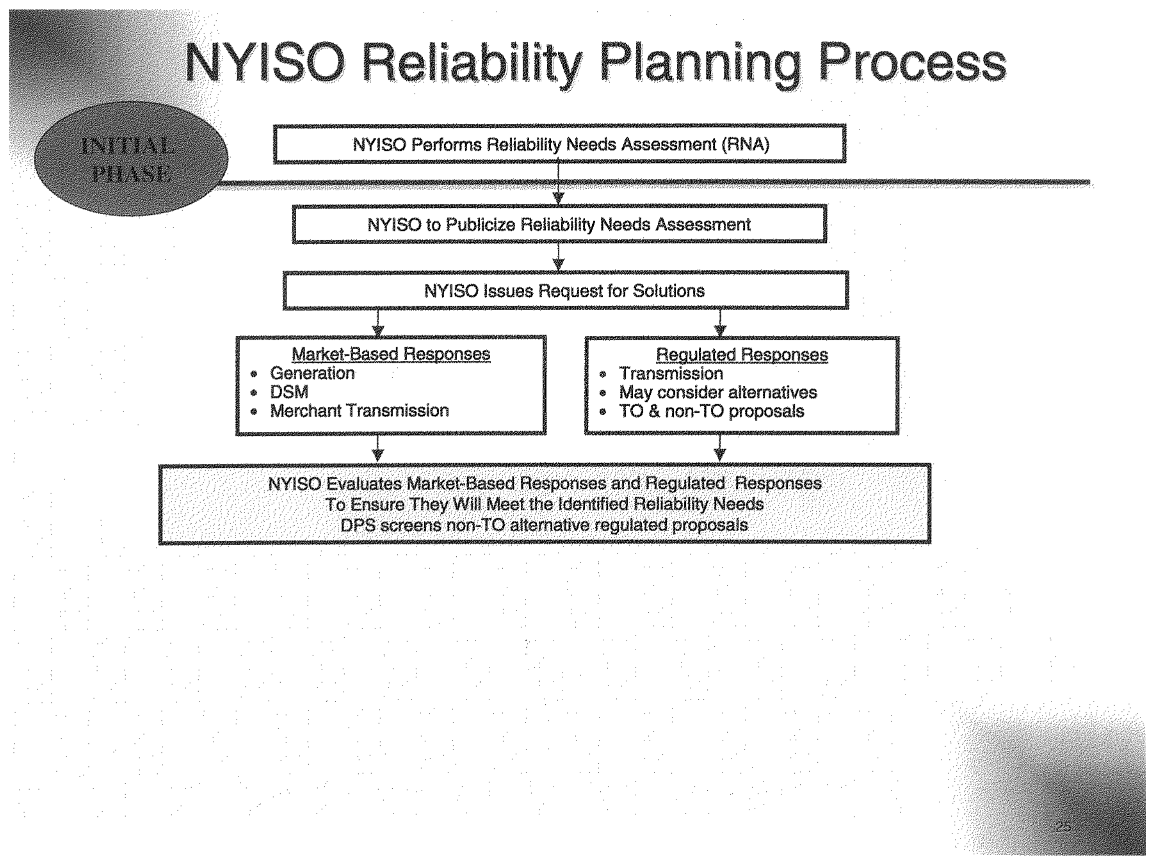
NYISO Performs Reliability Needs Assessment (RNA)

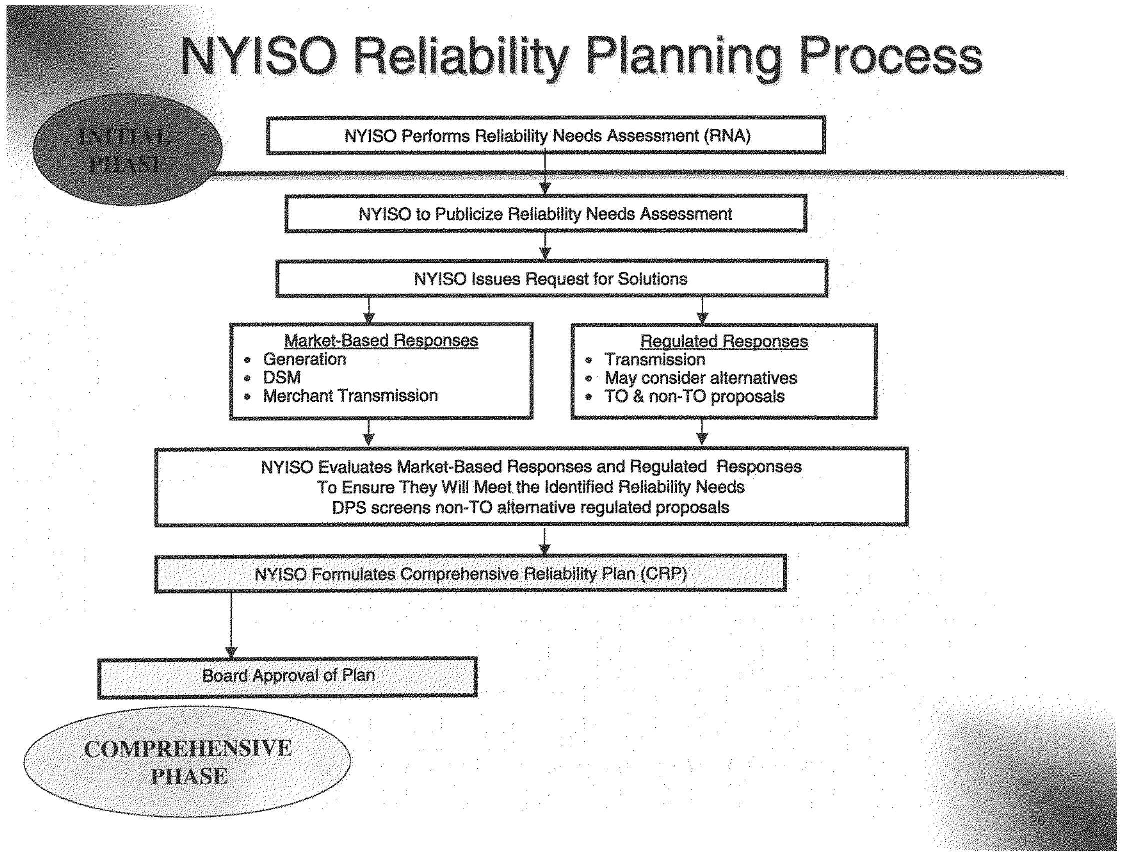

NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
21

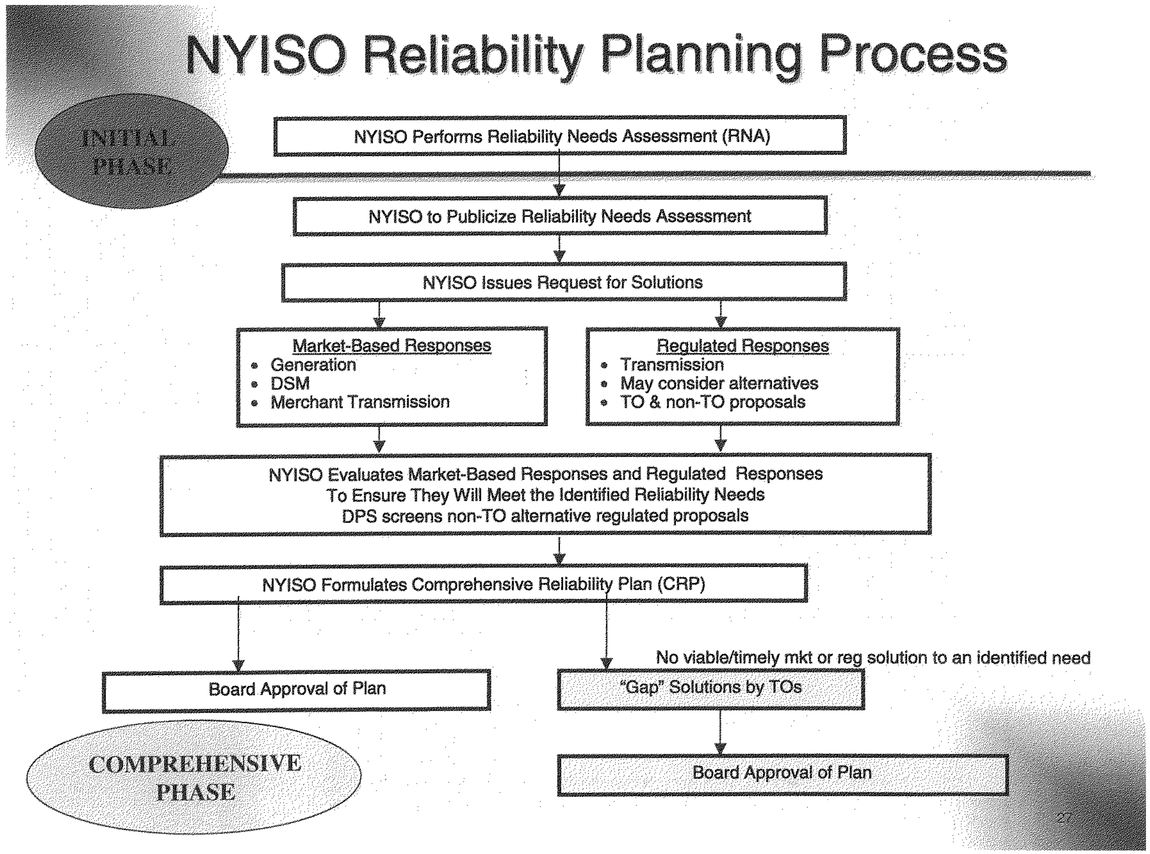

NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
NYISO Issues Request for Solutions
22


NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
NYISO Issues Request for Solutions
Market-Based Responses
Generation
DSM
Merchant Transmission
23


NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
NYISO Issues Request for Solutions
Market-Based Responses
• Generation
• DSM
• Merchant Transmission
Regulated Responses
• Transmission
• May consider alternatives
• TO & non-TO proposals
24


NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
NYISO Issues Request for Solutions
Market-Based Responses
Generation
DSM
Merchant Transmission
Regulated Responses
Transmission
May consider alternatives
TO & non-TO proposals
NYISO Evaluates Market-Based Responses and Regulated Responses
To Ensure They Will Meet the Identified Reliability Needs
DPS screens non-TO alternative regulated proposals
25


NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
NYISO Issues Request for Solutions
Market-Based Responses
• Generation
• DSM
• Merchant Transmission
Regulated Responses
• Transmission
• May consider alternatives
• TO & non-TO proposals
NYISO Evaluates Market-Based Responses and Regulated Responses
To Ensure They Will Meet the Identified Reliability Needs
DPS screens non-TO alternative regulated proposals
NYISO Formulates Comprehensive Reliability Plan (CRP)
Board Approval of Plan
COMPREHENSIVE PHASE
26


NYISO Reliability Planning Process
INITIAL PHASE
NYISO Performs Reliability Needs Assessment (RNA)
NYISO to Publicize Reliability Needs Assessment
NYISO Issues Request for Solutions
Market-Based Responses
• Generation
• DSM
• Merchant Transmission
Regulated Responses
• Transmission
• May consider alternatives
• TO & non-TO proposals
NYISO Evaluates Market-Based Responses and Regulated Responses
To Ensure They Will Meet the Identified Reliability Needs
DPS screens non-TO alternative regulated proposals
NYISO Formulates Comprehensive Reliability Plan (CRP)
Board Approval of Plan
No viable/timely mkt or reg solution to an identified need
"Gap" Solutions by TOs
Board Approval of Plan
COMPREHENSIVE PHASE
27

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Planning Summary

- The Comprehensive Reliability Planning Process (CRPP) is designed to maintain the reliability of the bulk power system
- The CRPP prefers market-based solutions
- The CRPP obligates the TOs to develop solutions for reliability needs if market-based solutions are not sufficient

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Regional Compatibility

- Participation in our markets by outside resources.
- Have had over 2700 MW of capacity bought from out-of-state sources.
- Rule compatibility is important.

NEW YORK INDEPENDENT SYSTEM OPERATOR
Building the Energy Markets of Tomorrow . . . Today

Conclusions

- Ensuring resource adequacy requires:
  - *Well functioning energy and ancillary service markets*
  - *Properly designed capacity markets*
  - *Comprehensive planning process*
  - *Regional compatibility*

Mr. ISSA. Mr. Brandien.

STATEMENT OF PETER BRANDIEN

Mr. BRANDIEN. Thank you, Mr. Chairman and members of the Subcommittee on Energy and Resources. I think I have a number of positive points to report to you today about southwest Connecticut and whether or not it is going to continue to be on the list as we move forward.

For the record, my name is Peter Brandien. I'm the vice president of system operations at ISO New England. My remarks will address the challenges facing New England and southwest Connecticut in particular and the actions taken by the ISO and the stakeholders to address the long-term concerns.

First off, I want to emphasize that the ISO plans and operates the bulk power system in New England, including southwest Connecticut, to meet reliability standards and the criteria established by ISO New England, the North America Electric Reliability Council and the Northeast Power Coordinating Council.

I agree in general with the FERC observation that there is inadequate capacity in southwest Connecticut and that no significant capacity has been added since 2004 and that the transmission system is operating to its limit.

The ISO forecasts possible recordbreaking demand for electricity in New England this summer. On average, summer peak demand is growing at 2 percent per year in New England, which equates to about 500 megawatts or one combined cycle generating plant. The summer peak in southwest Connecticut is also growing at the same 2 percent per year.

We expect the region will have adequate resources this summer. However, the region or local areas could experience tight supply conditions if generation is constrained or if hot, humid weather increases demand. In these cases, the ISO has longstanding procedures to maintain reliability. These include the activation of demand-response resources, purchasing power from neighboring control areas and implementing voltage reductions. These procedures also include public appeals for conservation through the media; and, in the past, we have had very good relations with the media getting the word out and the response that we have had from our customers.

As a last resort, after all operating procedures have been exhausted, the ISO may be required to institute controlled power outages to maintain reliability in the bulk power system if the regional demand for electricity exceeds the supply.

The ISO has developed a communication protocol to inform the public officials throughout New England of the actions taken by ISO New England to manage the bulk power system under these type of circumstances. We keep them informed as the system gets tighter and tighter so they are not caught unaware at the end. We have a communication protocol with a caution, watch, warning type thing so that people are aware and we get the information out to the media.

ISO has identified a lack of resources to ensure reliability in southwest Connecticut and in 2004 secured emergency demand-response resources for that area through a competitive bid. The RFP resulted in additional quick-start capacity for the summer peak period for 2004 through 2007. Although resources haven't been added since 2004, that RFP did take into consideration the requirements that we would need through 2007, recognizing that the transmission upgrades would not be there. The RFP was designed to bridge these gaps until these transmission reinforcements were put in place.

The ISO has worked with the New England stakeholders to develop long-term solutions for southwest Connecticut.

The State of Connecticut has approved major transmission reinforcements in southwest Connecticut. The Southwest Connecticut Reliability Project will extend the 345 network, which is the backbone of the transmission system, in New England into southwest Connecticut. This will be done in two phases. The first phase will be in service by the end of this year, December 2006; and the second phase is expected to be in service by the end of 2009. While these projects will not be in place for this summer, they are critical to ensure the reliability in southwest Connecticut for the long term. There is a significant reliability benefit to get that first phase in 2006, and we will see these benefits even though the second phase will not be in service until 2009.

One of the responsibilities delegated to the ISO by the FERC is to develop a regional system plan for an open stakeholder process that identifies a need for additional infrastructure and provides solutions to ensure reliability for New England. We take that responsibility very seriously, and the ISO identified the need for transmission reinforcements in southwest Connecticut in our 2001 regional system plan, which was the first year that ISO published a regional system plan.

On June 15, 2006, the FERC approved the settlement agreement for a new Forward Capacity Market in New England under which the ISO will conduct auctions beginning in 2008 for capacity resources to be developed beginning in 2010. The new capacity market is the result of a lengthy stakeholder process, subsequent litigation and, ultimately, settlement discussions surrounding the best approach to meet New England's growing need for capacity.

On May 12, 2006, the FERC approved the ISO and NEPOOL's proposal, known as Phase II of the Ancillary Services Model Project, to develop much-needed fast-start resources to provide reserves, particularly in the low pockets throughout New England. ISO is scheduled to implement this new market October of this year.

In conclusion, while there are significant challenges in southwest Connecticut that will persist until the planned infrastructure improvements are complete, ISO New England has procedures in place to operate the system reliably in New England and southwest Connecticut should emergency actions be required this summer. For the long term, a combination of transmission projects and wholesale market improvements are intended to provide additional capacity in southwest Connecticut to meet the area's growing demand for electricity.

I would also like to say that we have transmission projects into our other load center, the Boston area, significant transmission system upgrade as well as transmission projects that are approved and under construction to reinforce our ties with New Brunswick and also improve the reliability in Northwest Vermont. So through this regional system planning process we have sited and have a number of transmission projects throughout New England that will improve the overall reliability.

Thank you.

Mr. ISSA. Thank you.

[The prepared statement of Mr. Brandien follows:]

G0 193221-6

ISO new england

Statement of ISO New England Inc.
Before the House Committee on Government Reform
Subcommittee on Energy and Resources

Oversight Hearing: "Can the US Electric Grid Take Another Hot Summer?"
Rayburn House Office Building, Washington, D.C.

July 12, 2006

Thank you Chairman Issa and Members of the Energy and Resources Subcommittee for the invitation to appear before you today. For the record, my name is Peter Brandien. I am Vice President of System Operations for ISO New England. ISO New England is the Regional Transmission Organization (RTO) for New England, regulated by the Federal Energy Regulatory Commission (FERC) and serves as the independent system operator for the New England bulk power system.

Prior to joining ISO New England in April 2004, I oversaw the bulk power system in Connecticut as Director of Transmission Operations for Northeast Utilities.

My remarks will address the challenges facing New England this summer and Southwest Connecticut in particular and actions being taken by the ISO and stakeholders to address long-term concerns.

First, I want to emphasize that the ISO plans and operates the bulk power system in New England – including Southwest Connecticut – to meet reliability standards and criteria established by the ISO, the Northeast Power Coordinating Council and the North American Electric Reliability Council.

I generally agree with the FERC's observations that there is inadequate capacity in Southwest Connecticut and that no significant additional capacity has been added since 2004, and that the transmission system is operating at its limit.[1]

Extended periods of extreme heat and humidity, which could push demand above record levels, as well as unplanned transmission or generation outages, would pose additional concerns for Southwest Connecticut. Southwest Connecticut is a load pocket, characterized by high demand for electricity and limited amounts of local generation and limited ability to import power from the rest of New England and New York.[2] Furthermore, several of the generating units in Southwest Connecticut are among the oldest units in New England and there are constraints on the ability to move power within Southwest Connecticut on the existing transmission system. Finally, wholesale electricity prices in Southwest Connecticut tend to be higher than the rest of New England primarily due to the limited infrastructure available to serve that area.

Summer Outlook

The ISO forecasts possible record-breaking demand for electricity in New England this summer. New England could exceed last year's record by 140 MW (0.5%) under normal weather conditions and by 1900 MW (7%) under more extreme weather conditions. On average, summer peak demand is growing at approximately 2% per year in New England, which is the equivalent of needing to add a large 500 MW generating unit each year primarily to meet growing demand for air conditioning. Summer peak demand is growing by approximately 2% per year in Connecticut and Southwest Connecticut as well.

---

[1] *2006 Summer Energy Market Assessment*, Federal Energy Regulatory Commission, May 18, 2006.
[2] The Southwest Connecticut area represents approximately 25 percent of the land area of Connecticut and 50 percent of the state's peak demand for electricity. It is comprised of 54 of the 169 towns in Connecticut.

We expect that the region will have adequate supplies for the summer, however, the region or local areas could experience tight supply conditions if generation is constrained or if hot and humid weather increases demand. In these cases, the ISO has a series of long-standing procedures to maintain reliability.

These include the activation of demand-response resources, purchasing power from neighboring Control Areas, and implementing voltage reductions. These procedures also include public appeals for conservation through the media. There are two categories of public appeals: The ISO may issue a "Power Watch" as an appeal for conservation or a "Power Warning" as an *urgent* appeal for conservation. We may also request that the region's governors reinforce the ISO's public appeals for conservation. These procedures help maintain operating reserves when supplies are tight and can reduce – but may not eliminate – the need for more serious actions by system operators.

As a last resort, and after all other operating procedures have been exhausted, the ISO may be required to institute controlled power outages to maintain the reliability of the bulk power system if the region's demand for electricity exceeds available supplies.

The ISO has developed a communications protocol to inform public officials throughout New England of the actions taken by the ISO to manage the bulk power system under these types of circumstances. The ISO tests this protocol regularly with public officials in preparation for actual system emergencies.

Southwest Connecticut Gap RFP

The ISO has identified a lack of resources to ensure reliability in Southwest Connecticut and in 2004 we secured emergency demand-response resources for that area through a competitive solicitation, or RFP. The RFP resulted in additional quick-start capacity for the summer peak for the period 2004 to 2007. The RFP was designed to bridge a reliability gap until planned transmission reinforcements in Southwest Connecticut begin to come online.

As of July 3, 2006, there are more than 250 MW of resources in Southwest Connecticut that are capable of responding to dispatch instructions from the ISO to reduce demand on the bulk power system within 30 minutes. These resources in Southwest Connecticut account for more than half of the 30-minute demand response resources throughout New England. The demand-response resources in Southwest Connecticut have been activated on two occasions: 1.) On August 14, 2003 during the Northeast Blackout; and 2.) On July 27, 2005 when New England set a new record for summer peak electricity demand.

The ISO has also worked with New England stakeholders to develop longer-term solutions for Southwest Connecticut.

Transmission Projects

The State of Connecticut has approved major transmission reinforcements in Southwest Connecticut. Each of these projects has undergone a separate reliability review by the ISO to allow these projects to interconnect to the bulk power system. The Southwest Connecticut Reliability Project will extend the 345-kV network, which is the backbone of the New England bulk power system, into Southwest Connecticut in two phases. The first phase is expected to be in service by December 2006 and the second phase is expected to be in service by the end of 2009. While these projects will not be in place for this summer, they are critical to ensure reliability in Southwest Connecticut for the long-term.

One of the responsibilities delegated to the ISO by the FERC is to develop a regional system plan through an open stakeholder process that identifies the need for additional infrastructure and provides solutions to ensure a reliable power system for New England. We take that responsibility very seriously. The ISO identified the need for transmission reinforcements in Southwest Connecticut in our 2001 regional system plan. As you are aware, transmission projects require long lead times. The Southwest Connecticut Reliability Project, for example, is expected to be completed eight years after the filing of the initial siting application.

Market Enhancements

On June 15, 2006, the FERC approved a settlement agreement for a new Forward Capacity Market (FCM) in New England under which the ISO will conduct auctions beginning in 2008 for capacity resources to be delivered beginning in 2010. The new capacity market is the result of a lengthy stakeholder process, subsequent litigation and ultimately settlement discussions surrounding the best approach to meet New England's growing need for capacity.

On May 12, 2006, the FERC approved the ISO and NEPOOL's proposal, known as Phase II of the Ancillary Services Market project (ASM Phase II), to develop much-needed fast-start resources to provide reserves, particularly in locations that have relied on more costly and inflexible generating units to ensure reliable service. ISO is scheduled to implement this market in October 2006.

In conclusion, while there are significant operational challenges in Southwest Connecticut that will persist until planned infrastructure improvements are complete, ISO New England has procedures in place to operate the system reliably in New England and

Southwest Connecticut should emergency actions be required this summer. For the long-term, a combination of transmission projects and wholesale market improvements are intended to provide additional capacity in Southwest Connecticut to meet that area's growing demand for electricity.

Thank you. I would be pleased to answer any questions.

Mr. ISSA. Mrs. Currie.

STATEMENT OF PHYLLIS E. CURRIE

Ms. CURRIE. Good afternoon.

Mr. ISSA. The thing that is scary is that Peter said he provides it, but you say wait a second if he is going, "What is that button?" That is not something you want to hear in switching power, is it?

Ms. CURRIE. That is true.

Good afternoon. I am Phyllis Currie, general manager of the Pasadena Water and Power Department of the city of Pasadena, CA. My comments this afternoon speak to conditions in southern California, which were also the subject of Mr. Mansour's comments.

Pasadena is a municipal electric utility that is located geographically in the Los Angeles basin, and electrically we are within the control area of the CAISO.

Pasadena distributes electricity to approximately 61,000 retail customers. We buy power from and sell power to participants in California and the regional wholesale power markets; and we also are both a transmission customer of the CAISO and also a participant and transmission owner, which means we have turned over operational control of our transmission assets to the CAISO.

I also serve as the president of the Southern California Public Power Authority; and that consists of 11 utilities and 1 irrigation district, all public power. Collectively, we serve over 2 million people in southern California.

SCPPA was formed in 1980, and the purpose was to facilitate joint investment of generation and transmission projects which our members would not have been able to finance alone. We have included a map in my written testimony that shows you all the projects that we are a part of.

In my written testimony, I describe in detail the recent investments by both Pasadena and SCPPA; and these include generation, transmission, and natural gas reserves which we believe will give our customers the adequate reliability and deliverable power that they deserve. These investments are also available to help the region overall meet the summer peak demand.

I want to emphasize the need for the continued close coordination among the CAISO load-serving entities like Pasadena and the other SCPPA utilities and regulators during the summer to assure that the expectation of our customers for reliable power are met.

Finally, I want to voice concern about the market redesign and technology upgrade proposal that Mr. Mansour referred to, and this is something that the CAISO has filed with FERC.

In my role at Pasadena and at SCPPA and in my former life as CFO of the L.A. Department of Water and Power, I have had a lot of experience in financing generation and transmission projects; and our concern is that what attracts capital investment are clear, simple, and stable rules that allow investors to understand the risk that they will incur and to reduce those risks.

Pasadena and the SCPPA members were very concerned that the market rule changes that are being proposed will discourage development of much-needed generation and transmission and will inhibit efficient use of all available resources on a regional basis. The MRTU finding, which is over 5,000 pages, is 180 degrees away from the direction that investors want and need. The proposed rules are not clear, they're not simple, and they're not stable.

To give you an example, the MRTU proposal does not provide a mechanism to ensure that load-serving entities like Pasadena are able to obtain the long-term transmission rights as directed by Congress in the Energy Policy Act of 2005. Such rights were one of the biggest issues in the electricity title of that act, and the MRTU proposal is not only inconsistent with Congress' intent, but it also does not conform to the very constructive rule on long-term rights that FERC issued in 2006.

In order to invest in long-term-generation load serving, entities like Pasadena need to know that they are able to have transmission over the long term so that they have certainty about the deliberate cost of energy to consumers.

Another example, the MRTU adopts a complex series of scheduling processes that differ from prevailing practices in the rest of the western interconnection. This has the effect of discouraging transactions among participants in the western market and increase the cost of those transactions that do occur.

Bottom line is that the MRTU proposal at this point does not permit a reasonable degree of cost predictability and in our opinion will not facilitate market transactions or interoperability in the western interconnection.

Twelve western senators also voiced their concern by writing to FERC noting these concerns and urging that the Commission should, "proceed cautiously and provide a thorough vetting of the issues raised." A copy of the Senate letter is included in my written testimony.

However, I want to assure you that the public power community is committed to working with all parties including the CAISO to ensure that this summer all of our customers have the energy that they need. I took the opportunity during your break to give Mr. Mansour a very detailed idea of what our issues are.

In conclusion, I thank you for this opportunity and look forward to answering your questions.

Mr. ISSA. Thank you.

[The prepared statement of Ms. Currie follows:]

Testimony of Phyllis E. Currie
General Manager of Pasadena Water and Power (PWP)
of the City of Pasadena
and
President of the Southern California Public Power Authority (SCPPA)

House Government Reform, Energy and Resources Subcommittee
"Can the U.S. Electric Grid Take Another Hot Summer?"
July 12, 2006

My name is Phyllis E. Currie. I am the General Manager of Pasadena Water and Power of the City of Pasadena, California ("Pasadena"). Pasadena is a municipal electric system located geographically within the Los Angeles Basin and electrically within the Control Area of the California Independent System Operator Corporation ("CAISO"). In addition to distributing electricity to over 61,000 (metered) customers, Pasadena both buys power from and sells power to other participants in the California and regional wholesale markets. Pasadena is both a transmission customer of the CAISO and a Participating Transmission Owner ("PTO"), meaning we have transferred operational control of our transmission assets to the CAISO.

I also serve as the President of the Southern California Public Power Authority ("SCPPA"), a joint powers authority of eleven municipal electric systems and one irrigation district in Southern California, that collectively serve over 2 million customers. Beginning in 1980, SCPPA members banded together to jointly invest in generation, transmission, and renewable energy projects that most SCPPA members would not have been able to undertake individually.

Today I would like to discuss three areas which are interrelated and relevant to the topic of reliability in Southern California, both today and moving forward:

- First, I would like to take a few moments to describe Pasadena and SCPPA and the investments in generation and transmission that we have made to ensure that our customers have adequate and deliverable power to meet their needs.

- Second, I would like to emphasize the need for close coordination among the CAISO, Load-Serving Entities (LSEs) like Pasadena, and regulators during this upcoming summer in order for all to ensure that the expectations of our customers for reliable service are met. (A LSE is an entity, which may be either publicly-or investor-owned, that is obligated by law or contract to provide electric service to end-use customers.)

- Third, I would like to sound a cautionary note going forward. Pasadena and other members of SCPPA are concerned that California may be headed down a path that erodes, rather than ensures the <u>clarity, simplicity and stability</u> required to encourage investment in generation and transmission necessary to serve customers reliably and at a reasonable cost. Our concerns arise from proposed changes to the California market structure, called the

Market Redesign and Technology Upgrade ("MRTU"), currently being considered by the Federal Energy Regulatory Commission (FERC).

Reliability Through Assets – A Commitment to Investment by Pasadena and SCPPA Members

Historically, Pasadena, other SCPPA members, and indeed all of the municipal power community in California (which collectively serves 25-30% of California's electric retail load) made the determination that, while they are part of a larger and interconnected electrical grid that must work in harmony to ensure reliable and economic operation, they could not rely on others to meet the expectations of their customer-owners for reliable and reasonably priced power.

Pasadena has 200 Megawatts (MW) of generating capacity within the City itself, which represents approximately two-thirds of Pasadena's peak requirements. This includes an $82 million investment in 2004 to add 90 MW of peaking capacity. Pasadena makes its unused capacity available to the CAISO to augment state energy supplies.

Through SCPPA, and in conjunction with other municipal power systems, Pasadena has invested in a share of generation, transmission, and long-term natural gas resources. (See attachment B for map of SCPPA projects.) These projects include:

- the **Southern Transmission System**, which brings power from the Intermountain Power Project (IPP) in Utah (including 107 MW contracted by Pasadena) and other power resources in Utah and the Mountain states to Southern California;

- the **Palo Verde Nuclear Project** in Arizona, from which Pasadena is entitled to 10 MW, and;

- the **Pacific Northwest DC Intertie** transmission line from the Northwest to Southern California, as well as the **Mead-Adelanto and Mead-Phoenix** transmission lines from the Southwest to Southern California, which are used to import firm power from Hoover Dam in Nevada, Palo Verde in Arizona, and the Bonneville Power Administrations in Oregon as well as power from other resources in the Northwest and Southwest.

SCPPA Projects

More recently, Pasadena has invested in a number of SCPPA projects, which added both natural gas-fired and renewable energy supplies:

- **Magnolia Power Project, located in Burbank.** This 310 MW natural gas-fired, combined-cycle combustion turbine unit is unique in several respects, such as: it is "load-centered" generation located in an urban environment; it obtained air quality permits to operate in the Los Angeles Basin; it is designed to use treated effluent from the City of Burbank's wastewater treatment plant; it has zero liquid discharge from the plant site; and each participant is allowed to individually schedule its portion of the project output. The project was chosen as the "Power Plant of the Year" by Platt's Power Magazine in international competition in 2005.

- **Natural Gas Investments**. These investments include a recently completed $300 million purchase of natural gas reserves in Pinedale, Wyoming to ensure a reliable fuel supply for the Magnolia Project at stable prices not subject to market volatility.

- **Renewable Projects.** In addition to the Azusa Hydroelectric Plant and Pasadena's share of the output from the Hoover Dam, Pasadena has added to its renewable portfolio by participating in the following SCPPA projects:

   1. **High Winds Project.** Pasadena contracted for a 6 MW share in the High Winds Generation facility in Solano County in Northern California. The plant includes 81 state-of-the-art Vestas V80 windmills, lining the ridge tops of the Montezuma Hills.

   2. **Gould Geothermal Project.** Through a 25 year agreement developed by SCPPA members, Pasadena will obtain a 3 MW share of a geothermal project in California's Imperial Valley.

   3. **Chiquita Canyon Landfill-Gas-to-Energy Project.** Through a 20 year agreement, Pasadena will obtain a 2.2 MW share of a project in Valencia, California which will capture gases produced from decomposing matter from a landfill and convert it to energy.

In total, this diverse portfolio of generation, much of it located within the constrained area of Southern California, combined with transmission investments, has enabled Pasadena and other SCPPA members to meet the needs of our customers and contribute to overall system reliability.

And we are not done. Pasadena and SCPPA are examining additional transmission and generation investments. For example, SCPPA is working to complete an upgrade to the Southern Transmission System (STS) Project that will be used to transport additional resources, including renewable energy resources, from Wyoming and Utah into Southern California.

In addition, SCPPA along with two of its members (IID Energy and Los Angeles Department of Water and Power (LADWP)) are involved in the development of a new 1,200 MW transmission line from the Imperial Valley of California to the Los Angeles Basin, which is more commonly referred to as the "Green Path" Initiative. This new line will deliver geothermal, wind, and, potentially, solar power energy into the Los Angeles Basin and support overall grid reliability in Southern California.

SCPPA, through its joint membership, is also in the process of developing approximately 600 MW of renewable energy pursuant to its latest solicitation for offers. This new renewable energy will help SCPPA members meet their respective renewable portfolio standards (RPS). SCPPA members have an ongoing commitment to renewable energy.

I emphasize our history of investment and commitment to future infrastructure development not only to tout our own accomplishments a bit, but also to make a point. These investments are possible and desirable because of the clarity of purpose and rules under which we have operated historically. Our purpose as community-owned utilities is, simply, to provide reliable low-cost power to our customers. Simplicity, clarity, and stability of the market rules and the overall industry climate are what draw reasonably priced capital to the industry and help lower overall costs to consumers in this capital intensive business. As I will discuss in more detail below, Pasadena and other SCPPA members are concerned that proposed changes to the market design will erode those foundational elements for prudent and sound infrastructure investment.

Summer 2006

First and foremost, let me emphasize that when it comes to real-time grid operation, all market participants have the obligation to work closely together to ensure the greatest level of reliability that can be provided by the system in place. As part of the CAISO Control Area, Pasadena recognizes the CAISO's responsibility to ensure short-term grid reliability and works closely on several levels with the CAISO to maximize coordination of system operations. For example, Pasadena participates in regularly scheduled operations calls held by CAISO during times of system stress. Furthermore, as a member of the Western Electricity Coordinating Council (WECC), Pasadena adheres to the generally-accepted industry standards and practices, and we support WECC's expeditious implementation of regional reliability standards, as required under the Energy Policy Act of 2005 ("EPAct 2005").

Individually, Pasadena has taken proactive steps to enhance readiness for this summer. In addition to our investments in generation and transmission, we have tailored our power plant maintenance schedules to promote the maximum availability of our units to meet peak demands. We have initiated proactive programs with our large customers to prepare for summer conditions. As directed by our City Council, Pasadena has invested in energy efficiency and conservation programs targeted at reducing our peak demand, which is directly relevant to ensuring reliable operation during stressed conditions. These investments include unique "energy storage" technologies that shift air conditioning loads to off-peak periods. Commercial and residential air conditioning loads are a large driver of our system peak and the California peak, particularly in warmer inland areas. In short, Pasadena has worked proactively to prepare for summer 2006, and we look forward to continued coordination with the CAISO to ensure the maximum level of operational reliability possible.

MRTU - A Cautionary Note

I have reviewed FERC's *Summer Energy Market Assessment 2006* ("Assessment") which prompted this hearing, and I would like to offer some observations about the market descriptions and investment issues addressed in that report. In my experience as the former Chief Financial Officer (CFO) of LADWP, what attracts capital investment in generation and transmission are clear, simple and stable rules that investors understand and that reduce their risks.

What I see in the Assessment are references to a number of "market design" mechanisms, such as "scarcity pricing;" "real time models to better reflect local prices;" "improved modeling of gas turbines ...[to] improve real-time price accuracy;" and "dispatch changes to decrease uplift," to name a few. I do not believe the Commission intended to suggest that these mechanisms are solutions to reliability problems, but I must observe that these types of market minutia do not build generation and transmission. While I have not focused on the specific problems of other regions of the country that have adopted so-called "Day Two" market designs, I am concerned that if we in California follow suit and embrace similar complex market mechanisms, we will lose sight of the fact that clear, simple and stable rules are what attract investment capital.

I will reiterate that, while Pasadena and SCPPA members remain committed to working with the CAISO to maintain reliable grid operation, we are concerned that proposals by the CAISO at FERC to change market rules will erode the very stability and certainty on which Pasadena has relied to build generation and transmission. These market rule changes, in the MRTU as proposed to the FERC, will discourage development of much needed transmission infrastructure and generating resources and will inhibit efficient use of all available resources on a regional basis. In a nutshell, the MRTU proposal does not permit a reasonable degree of cost predictability, and it will not facilitate market transactions among the sub-regions of the Western Interconnection.

Municipal systems and all other potential investors in generation and transmission resources face the difficult task of evaluating the potential risks and benefits of such investments. Clearly it is not humanly possible to eliminate all risks. But the MRTU proposal increases risks for many market participants and fails to take reasonable steps to mitigate them.

As a practical matter, buyers and sellers of energy in California must rely upon the CAISO for transmission service. But under the currently effective market structure, buyers and sellers may arrange for purchases and sales on a bilateral basis and simply arrange for delivery by the CAISO. Under the proposed MRTU Tariff, however, all transactions scheduled over the CAISO Controlled Grid will have to be settled through the CAISO's complex market structure. This mandatory buy/sell nature of the MRTU market structure will expose all market participants to expanded and inescapable exposure to financial risks.

For Load Serving Entities ("LSEs") within the CAISO Control Area, such as Pasadena, there will be no way to avoid the expanded risks. For sellers and buyers outside the CAISO Control Area, the expanded risks will either discourage transactions that require transmission over the CAISO Controlled Grid or increase the costs for such transactions as a result of increased risk.

The MRTU proposal currently includes general provisions for Congestion Revenue Rights ("CRRs") that have the intended purpose of providing a financial hedge for LSEs against congestion costs (*i.e.* charges that will be applied when the transmission grid is not capable of accommodating all desired transactions). Effective CRRs are absolutely critical to the ability of LSEs to manage the expanded price risks described above. Unfortunately, the MRTU CRR proposal in its current state provides no assurance that CRRs will provide an effective hedge against the expanded price risk faced by LSEs.

The FERC previously required the CAISO to provide actual CRR allocations to market participants simultaneous with the filing of the MRTU Tariff. *See Calif. Indep. Sys. Operator Corp.*, 105 FERC ¶ 61,140, at P 172 (2003) ("we will require that the CAISO file detailed information on the proposed first year allocation when it files its proposed tariff instituting the CRR allocation method"). The CAISO has not complied with that directive. The CRR provisions in the MRTU Tariff provide merely a theoretical framework that does not allow LSEs to evaluate in any concrete way the likely impact of the MRTU market design on their procurement plans and costs.

As mentioned above, our primary goal is to provide reliable and low-cost power to our customers. What these risks and increased transmission costs mean for cost-based entities such as Pasadena, and other public power utilities, is increased prices for ratepayers.

Moreover, the CRR process as proposed by the CAISO fails to provide any mechanism for long-term transmission rights (LTTRs) to facilitate long-term resource commitments. Indeed, explicit limitations on the extent of grandfathering for CRRs from year to year make it impossible for LSEs to count on CRRs to hedge long-term resource commitments. *See* MRTU Tariff § 36.8.3.5. The absence of any mechanism for long-term transmission rights is inconsistent with the requirements of Section 1233(b) of EPAct 2005 (amending Section 217 of the Federal Power Act) and with the FERC's previous and repeated directives to the ISO. *See Pacific Gas and Elec. Co., et al.*, 80 FERC ¶ 61,128, at p. 61,427 (1997) (directing the ISO in 1997 to make long-term firm transmission rights "available to all market participants in a non-discriminatory manner as soon as possible."); *Cal. Indep. Sys. Operator Corp.*, 87 FERC ¶ 61,143, at p. 61,572 (1999).

FERC issued on February 2, 2006 a draft rule to implement the long-term transmission rights ("LTTR") provisions of EPAct 2005 and we believe it is a good, strong rule that fulfills Congressional intent. However, the CAISO not only has failed to comply with the FERC's previous directives, but it also has asked the FERC to defer any requirement to provide long-term transmission rights pursuant to the new rule until at least one year after implementation of the MRTU proposal (now optimistically projected for November 2007).

The FERC, a number of state regulatory commissions, including the California Public Utilities Commission and local regulatory authorities all have devoted significant attention in recent months to the development of Resource Adequacy programs to encourage or require LSEs to procure power supply resources sufficient to meet the needs of their customers. The inability to predict future transmission costs or arrange for long-term transmission rights is a major impediment to fulfilling resource adequacy objectives.

Municipally-owned LSEs are not the only ones concerned with the degree of uncertainty involved in long-term resource commitments. Southern California Edison Company ("SCE") and the Pacific Gas and Electric Company ("PG&E"), the largest LSEs in California, also submitted comments to FERC on the MRTU proposal that highlighted concerns regarding the absence of detailed CRR provisions and provisions for long-term transmission rights. Congress spoke to the issue of long-term transmission rights in the EPAct 2005, and its message was clear. The FERC should not accept the CAISO's MRTU proposal unless and until the CAISO provides information on actual, final CRR rights and a mechanism to establish long-term transmission rights.

The MRTU proposal also intensifies on-going concerns with "seams" between the CAISO markets and other markets in the Western region. The term "seams" refers to differences in market designs and operating procedures that make it difficult to arrange for desired energy transactions among the various sub-regions in the West. There have been continuing seams problems between the CAISO and other sub-regions in the West since the CAISO began operations in 1998. Unfortunately, the MRTU proposal does nothing to minimize the seams problems and, in fact, includes features that will make them worse.

For example, the MRTU proposal includes a complex series of Day Ahead, Hour-Ahead Scheduling Process ("HASP") and Real Time market processes with scheduling timelines that differ from the prevailing practices in the rest of the Western Interconnection. Neighboring control areas, consistent with common industry practices, allow schedule changes up to twenty or thirty minutes before the active scheduling hour and even into the active scheduling hour.

Although the deadline for scheduling in the HASP under MRTU will be closer to the active scheduling hour than the deadline currently in effect under the CAISO's existing market design, it still will be at least forty-five minutes earlier than the prevailing practice in the remainder of the Western Interconnection. This has the effect of discouraging transactions among sub-regions in the West and increasing the prices for transactions that do occur. Indeed, several suppliers in areas outside the CAISO Control Area, including the Bonneville Power Administration, identified features of the MRTU market design that would discourage transactions with entities within the CAISO Control Area.

In addition, limitations in the settlements and bidding processes included in the MRTU proposal will both restrict and increase the risks associated with transactions between LSEs within the CAISO Control Area and potential buyers and sellers in other sub-regions of the West. If an LSE in the CAISO Control Area finds that it needs additional resources on an Hour Ahead basis, it will face a significant price risk for importing a resource from outside the Control Area. Under the complex MRTU settlements proposal, the import will be paid the Hour Ahead Locational Marginal Price ("LMP") at the import point, but the LSE arranging for the import will pay a different price for the load to be served by the import. This imposes additional price risks on the LSE that is attempting to procure sufficient resources to meet its customers' requirements.

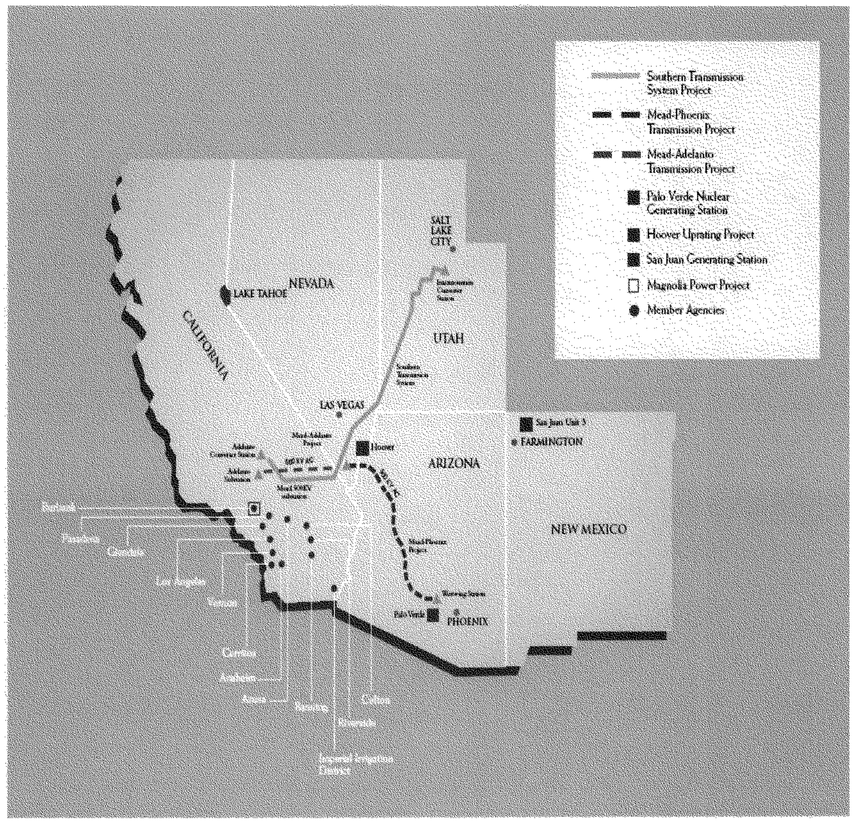
These concerns are among those that prompted twelve U.S. Senators to write recently to the Chairman of the FERC, Joe Kelliher, expressing concerns about the CAISO's market redesign proposal and requesting the Commission to "proceed cautiously and provide a thorough vetting of the issues raised," in particular, features such as centralized, bid-based dispatch of generation, locational marginal pricing for supply and financial rights in lieu of physical rights to manage congestion. The Senators encouraged FERC to "consider the impacts not only to California, but to those throughout the West." (See attachment B for a copy of the June 26 Senate letter to FERC.)

<u>Conclusion</u>

Pasadena has a long history of investment in generation and transmission, we have a strong working relationship with the CAISO to ensure system reliability, and we will continue to work cooperatively to keep the lights on. However, going forward, we believe that many of the market design mechanisms proposed in the CAISO's MRTU are ill-conceived, will not promote investment in generation and transmission in California, and may seriously hinder reliability of the Western grid.

Thank you for the opportunity to appear before the Subcommittee to express my views. I look forward to answering any questions you may have.

Attachment A



Attachment B

United States Senate
WASHINGTON, DC 20510

June 26, 2006

Chairman Joseph Kelliher
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Chairman Kelliher:

We are writing to request that the Federal Energy Regulatory Commission (FERC) not act in haste while considering the California ISO's proposal, called the Market Redesign and Technology Upgrade (MRTU). The potential impact to consumers in California and the entire West of this 5,000+ page filing (Docket No. ER06-615-000) deserves careful examination before FERC decides whether to approve or reject this complex proposal.

We are concerned that FERC thoughtfully consider the impacts not only to California consumers, but to those throughout the West. As you know, the Western grid is integrated and any changes to the California market will have implications throughout the West.

We know that a number of other entities have urged FERC to examine further the potential impacts of MRTU on the western wholesale electricity market. We too ask that the FERC Commissioners proceed cautiously and provide for a thorough vetting of the issues raised by this proposal. It is more important to get this done right than to get it done quickly. Thank you for consideration of our concerns.

Sincerely,

Barbara Boxer

Harry Reid
Patty Murray
John Ensign

Jon Kyl

Max Baucus

Craig Thomas

John McCain

Mr. ISSA. I want to thank all of you for making every effort to stay as close as you could to the 5 minutes.

Ms. Currie, I would like to hear more about, you know, the simplicity and the strategy, but I think what I'm probably going to do is ask Mr. Mansour to answer your questions in a moment, and I think that may be better to have somebody that can respond.

Before I do that, I want to ask all of you, in your individual areas, the ISOs and obviously within the Pasadena umbrella, if the worst case occurs, as in your chart, Mr. Mansour, but in all of yours, if the worst case occurs this year, that the highest likely outages occur somewhere in California, New York, New England, will we have power outages? Does your worst-case scenario assume that, unless everyone runs home and turns off their air conditioners, that we will have power outages if the worst occurs?

Mr. MANSOUR. Mr. Chairman, my definition of worst-case scenario is not just that everyone turns off their air conditioner. It is also high level of outages of generators more than the average we get. It is also outages of major transmission elements, as I said, one of the major entities with the West like 2,000 megawatts.

Mr. ISSA. I appreciate that. But if all of that happens——

Mr. MANSOUR. If all of that happens, if you have major transmission outages, a lot of generation out, more than normal, and extreme hot temperature, we will have outages. Some of them—hopefully, the majority of them will be the planned outages which is the one that is contracted for interruption. The amount that would be forced to be out, our role is to minimize that amount in terms of magnitude and duration.

But all of those scenarios are trained on. The operators are trained on how to respond to it, how to prepare in advance so that they do not propagate to the rest of the West and what is the recovery process so we can minimize the duration.

Mr. ISSA. Mr. Lynch. By the way, I'm mostly talking about, for all of us that are sort of my age, it is like the biorhythm charts where you have the ups and downs. I'm just talking about the likely high end of your range occurring at the likely high end of your range between transmission outage, production outages and, obviously, a hot day. I'm not talking about the earthquake. But it appears as though that is the answer, is, if those coincide, we will have either forced or nonforced outages predictably if all three line up.

Mr. MANSOUR. That is correct, sir. For example, the transmission outages, we had transmission outages over the last few weeks on major transmission lines because of eagle nesting and eagle activities and forest fires but not earthquakes.

Mr. ISSA. We should trim those eagles, I guess.

Mr. Lynch.

Mr. LYNCH. Your question I think takes on sort of a very far-reaching or a worst-case scenario as you put it. Within our planning and within the system that we have available, we do look at various contingencies and the N minus one contingency of losing the single worst—or I guess resource that you have out there, be it a transmission or a generating facility. The way our system is set up it can absorb that.

Actually, looking at New York City, because of the previous blackouts in and around the city, we go into thunderstorm alert at certain times in the summer and actually look at an N minus 2 criteria. Essentially, with the cables that we have out, we are almost in that right now, where we could still withstand a single loss of a major contingency, a resource being out or another transmission line.

After that, we get thin, and we go into emergency procedures, and I think Mr. Brandien outlined very similarly what we would do. You would look to your other control areas. You would curtail basic transactions across your borders. You would look for emergency power to come in. You would then look to some type of a notice and actually initiation of our demand-response programs.

In New York, we have two types, not only the emergency demand response but we contract ahead for demand response that we know that we can count on. We would basically call on those programs, and you would have to look at some type of voltage reduction. As the very last resort, I think you would be looking at some very localized types of load shedding or load management control. But you would have to get into a pretty dire situation.

That is not to say that the stars can't align and the biorhythm chart can't put all three lines crossing at the same time. Anything is possible. We saw that in 2003. But I think, overall, when you look at the system this summer, we run about an 18 percent reserve margin on the system. We actually have a little bit more than that. We do have the capability of imports and feel pretty comfortable, other than going to that extreme, extreme condition, that we should be good this summer.

Mr. ISSA. Mr. Brandien, I am making this more complicated perhaps in the question, I am just making the assumption that your goal is to be able to have the statistical inevitably that you will have transmission problems along unexpected outages on a hot day at some point. It is numerically—statistically, it is going to be and your goal is to be able to either have no outage or only dip in that situation to those that have been paid for that relief because that is part of the realignment plan. If that happens today—and you already have transmission problems, so I'm very confident the other two line up—you are going to be looking at keeping hospitals lit while turning off other people in the worst case.

Mr. Brandien, how would you be in that situation today.

Mr. BRANDIEN. I tend to be an optimist in these situations. I think the probability is low. We do a lot of things to ensure that the probability stays low: the maintenance we do on the infrastructure in the springtime; the maintenance that we do on the generators; looking at the various scenarios, high loads, high outages; get the word out to our constituents throughout New England, keeping them informed as we experience, say, the first outage and that the system is getting closer and hopefully the public responds and voluntarily reduces the load——

Mr. ISSA. Out of respect of the other Members' time, I'm going to cut short. I'm going to paraphrase what you said earlier, which was basically you have a plan to beg people to shut down things as part of your survival. So I'm going to make the assumption at this time you don't have the ability to do it by ordinary means, nor do you have advanced load shedding beyond industrial customers, and that is one of the concerns of this committee, that we apparently don't have that.

Ms. Currie, I'm assuming that you are going to say that, since you depend on other people, in your testimony you don't have a high confidence if those line up you are not going to have your customers denied power.

Ms. CURRIE. I think, to the contrary, as a municipal utility operator, we have adequate reserves to cover our customers. In fact, we have more than what is required.

We are, however, supportive of entire State; and so if the CAISO says there is a system-wide emergency, we will shut down our customers, even though we have adequate reserves for them, in order to support the rest of the State. That has happened in the past. It could happen in the future. Based on the CAISO's predictions, we're hopeful that we won't do that this summer.

Mr. ISSA. Thank you.

And, again, I'm going to respect the other Members and alternate and come back for a second round if there is time.

Mr. Higgins.

Mr. HIGGINS. Thank you, Mr. Chairman.

My questions are specific to the New York Independent System Operator. As I understand it, New York is a deregulated market. The process works in a way whereby the Independent System Operator establishes what the demand for the day is and then the producers—kind of like a reverse auction, if you will—the producers respond to that; and once the daily demand is met, that is the price paid to all of those who have submitted proposals.

Mr. LYNCH. It is not exactly like that. We actually run two markets a day ahead. Commitment market, which is a financial market, it is based on bids and offers. Generators will provide offers; and we will make commitments in a day-ahead scenario so that we feel, based on projections from the load-serving entities, that we have sufficient capacity met.

When we get into the real-time markets, you are correct, we are a balancing market. And if there are transmission constraints or generation outages, there is locational pricing. As a rule, there is a locational pricing, a current price that is out there. And what I think you are referring to is the uniform pricing, as opposed to bid-as-pay pricing where you would get whatever was bid in. But we actually look at a clearing price across the State.

The important point there is that it is a locational pricing; and, historically, prices upstate in the northern and western part of New York State have actually been lower than downstate in New York City and the Long Island area, specifically because of the constraints. In other times, when there are no constraints, you may have a unit setting the marginal cost or the lowest production price available across the State.

The way we run our markets, though, we do look at the lowest production cost. We do drive the system to the marginal cost, and I think that is one of the true benefits of what we do.

Overall, as I said, there would be very few instances when there are no constraints in the system, that a unit downstate would be setting the price for the entire State with the locational zones that we have in place.

Mr. HIGGINS. Statewide capacity supply, 40,000 megawatts?

Mr. LYNCH. Yes, we have about—I would say about—well, I will tell you exactly. We have a little over 39,642 megawatts of in-State supply. Our projected peak demand this year is a little over 33,000 megawatts. We look at about an 18 percent reserve. That is not counting our demand-side program. I mentioned that we have contracted forward for demand-side management, which we call special case resources, about 1,000 megawatts.

We also, since we run a capacity market in New York, we actually contract ahead for import capacity; and we have the capability to import about another 2,700 megawatts. So we have fairly good, sufficient capacity.

One of the things—and I think it goes back, Mr. Chairman, to your question on concerns about loss of contingency. We also have locational requirements for New York City where physically what we do is we project the peak demand for New York City and we require, physical, on the ground, of 80 percent of that peak capacity be located within the city. For Long Island, it is actually 95 to 99 percent of the physical capacity that is needed to meet their peak demand to be located within that boundary so that they are not depending on imports from transmission but actually have robust generation facilities within their geographical boundaries to meet those loads.

Mr. HIGGINS. What you are saying is a 39,000 megawatt capacity or supply and a peak demand of approximately 33,000 megawatts.

Mr. LYNCH. That is correct.

Mr. HIGGINS. It seems those margins are pretty tight.

Mr. LYNCH. It is 18 percent; and that is actually dictated through the NPCC, the Northeast Power Coordinating Council. They give us a criteria to look at our installed reserve margin, and it is different in different regions. Taking that criteria, we have come up with—and it has been pretty consistent over the last 5 to 10 years—of carrying about an 18 percent reserve margin.

Mr. HIGGINS. Right. But I've also read statements where you have encouraged the State legislature to site more plants presumably for the purpose of increasing supply capacity. If you are comfortable with that 18 percent margin, what is the basis for making or encouraging the siting of more plants to build in new supply capacity?

Mr. LYNCH. Well, from a market standpoint, when you look at a locational pricing—as I mentioned, we ask for a certain amount of capacity to be within New York City and also Long Island in running a market that is supply and demand and price is set by tighter supply. So the more supply that you have, obviously there is price alleviation both on the energy sides and the capacity side. So having more capacity available will actually provide a better mix, a better reliability.

Mr. HIGGINS. I'm sorry, but that also provides the cost-cutting stimulus that is promised from more competition.

Mr. LYNCH. Well, when you say cost-cutting stimulus, I think what you are looking at is competitive forces to come in and basically alleviate price pressures and actually reduce overall consumer prices.

Mr. HIGGINS. Isn't that the effect of more capacity?

Mr. LYNCH. More capacity will help.

I would say, though, that I don't agree with the statements that some entities have made that deregulation, especially in New York State, has resulted in higher prices. What you see is a phenomenon of gas prices and oil prices, especially over the last 3 or 4 years, just exponentially increasing over what anyone predicted.

When we do an analysis from 2000 to 2004 of fuel-adjusted prices we actually find that consumers have benefited, 5 percent reduction in overall prices. That is on a fuel-adjusted basis. I believe that the New York Public Service Commission came out with a study that basically replicated the same type of analysis and indicated that on a fuel-adjusted basis you had a reduction in pricing.

Mr. ISSA. Thank you. Thank you for your line of questioning.

The Chair will take a prerogative and perhaps agree with the gentleman in reverse. I think on both sides of the aisle here on all energy issues, including gas, oil, natural gas and electricity, a shortage in a free market will always lead to significantly higher prices. We may not be sure if an excess will give us lower prices, but I don't think there is any question today as we fill up at the pump that a shortage of refining or a shortage of capacity anywhere along the system inevitably leads to artificially higher prices, and it is something that this committee has been dedicated to on a bipartisan basis.

With that, Mr. Bilbray.

Mr. BILBRAY. Mr. Chairman, I just would like to point out in the California experience—Ms. Currie probably wasn't there—where we did have the shortage was actually public utilities that were wheeling and actually ending up making more off the situation than the private sector was at that time.

First of all, Mr. Lynch, 80 percent to 90, that is a pretty impressive number. What technologies are you using to generate within an urban area? Are you using natural gas or what combination are you using?

Mr. LYNCH. You are specifically talking about New York City and Long Island?

Mr. BILBRAY. Yes.

Mr. LYNCH. There are some older oil-fired-type plants there, but predominantly the new generation that comes in has been gas. It has been either combined cycle or what we call simple cycle, a combustion turbine. Predominantly, the new generation that I mentioned before has all been gas.

Mr. BILBRAY. Ms. Currie can you tell about the days we could burn oil, right, Ms. Currie?

Ms. CURRIE. Mr. Bilbray, if I might comment on your first comment, the public power utilities made investments that benefited the entire State and didn't get paid for them. Furthermore, FERC did a very exhaustive investigation as to whether or not we manipulated the market; and we were found not to have done that.

Mr. BILBRAY. There was no out-of-State sales?

Ms. CURRIE. There were out-of-State sales, but we were not market manipulators. We bought power and then turned it over to the

State to benefit the entire State. So we think we did the right thing during the last energy crisis, and we are prepared to continue to do that.

Mr. BILBRAY. I appreciate that information. The last we saw was that there was wheeling out to Arizona and some wheeling coming back between Arizona and Utah.

Ms. CURRIE. I think those things were thoroughly investigated by FERC, and we were exonerated.

Mr. BILBRAY. My question to you, if you were over at—in Los Angeles, we just decommissioned or—wasn't the Laughlin facility a joint project with Edison that the utility had for major generation for a while?

Ms. CURRIE. Well, that may be a little bit after my time. I retired from L.A. in 1999.

Mr. BILBRAY. They have decommissioned it since, but at the time it was a pretty big generator. I was just wondering—you have left there. If I can ask the representative from California, we just decommissioned a major facility that was generating for the Los Angeles air basin and has there been any replacement for that generation facility at Laughlin?

Mr. MANSOUR. If it is the Los Angeles Water and Power facility, it is not in the ISO control area. L.A.—it is a separate controlled area, and they are separate from the ISO. If you are talking about——

Mr. BILBRAY. Actually, it was a joint project between the utility and Edison in Laughlin. It was a slurry coal mixture operation that has been decommissioned. I was wondering, as it is going to be down, how to you replace that generation?

Ms. CURRIE. You may be thinking of the Navajo project. L.A. has over 7,000 megawatts of capacity right now, and their peaks are in the mid-5,000's. So even with the loss of that capacity they would still be well in excess of what they need to serve their customers and support the rest of the State.

Mr. MANSOUR. I can tell you, as I said in my testimony, Mr. Bilbray, there was 14,000 megawatts of new generation and retirement of 6,500 megawatts total. So the net is about 8,500 since the crisis time. It is not necessarily growing in pace with the faster growth, but there was a net of 8,500 megawatts in total.

Mr. BILBRAY. Thank you very much.

No further questions, Mr. Chairman. I yield back.

Mr. ISSA. Thank you.

On the Navajo, that generation shut down, as I understand it, not just because of, if you will, air quality. It shut down, as I understand, because of water—inability to get a source of water.

Ms. CURRIE. Yes.

Mr. ISSA. And eventuality that even if they got that they only had so many years. It was more complex shutting down of a facility than just air quality.

Ms. CURRIE. Yes, it was; and I think it is important to point out that, over the last 5 years, the municipal community of California has added 2,800 megawatts of capacity. If you look at the total amount of demand that we represent, that's about 20 percent. In addition to that, we've added another 1,000 megawatts of repowered generation, which not only gives you more efficient generation but it also cuts down on air quality issues.

Mr. ISSA. Just a brief answer, if possible, relative to California. We took off, you know, 8,500—we have 6,000 megawatts lost, 14 brought in, 8.5 net. Excluding the Navajo facility, much of the rest of that power, except for air quality rules, as I understand, could have been kept for peak. But, in fact, it was taken off to get credits, when in fact the facility is going to cost money to dismantle and a relatively low cost to keep it as peak.

Is that your assessment? California's air quality rules—I am not disagreeing with them—but do encourage the dismantling of what would otherwise be fully depreciated older facilities that could be used in times of shortage?

Mr. MANSOUR. I can tell you, Mr. Chairman, that at least in the last two—since I have been on the job—were shut down based on public pressure. Mojave is—you know, Edison tried to make the point to keep it; and they still for a while tried to even repower unsuccessfully. So they had to shut it down.

Hunter's Point in the San Francisco area has been a point of dispute for a long, long time. Every politician in California I think lobbied to shut it down, and finally it did shut down. It is a combination of quality, neighborhood kind of uneasy about generation close to the load center. Which really makes the point, when people talk about generation and new transmission, I am yet to see a neighborhood that is willing to accept a generation plant rather than a transmission. It is part of the difficulty between the two, so it is a combination.

Mr. ISSA. Going back to advanced transmission, and I think all of you—well, let me rephrase that. Certainly those of us with mountains are particularly eligible to use the pump-storage-type technology which New York has some, New England has some capability. California has two sets of ridge lines that run up and down the State. We're probably the wealthiest, other than the sort of Rocky Mountain States, in the ability to put those in.

Assuming that the FERC works diligently and relatively quickly, and can give us a formula to fairly analyze that, when we are looking not at the LEAPS project, which is one particular project, happens to be in my district, but when we are looking at the future of relatively low cap cost compared to equal facilities of conventional generation and we are looking at putting in that 8 hours of peak in the worst case, does this type of technology have the potential where you have the large drops, either water or the ability to put in artificial water—does this represent what should be a substantial portion of our peak power? Obviously, we have the "what ifs," but, in concept, does it?

Mr. MANSOUR. I will start, Mr. Chairman; and I agree fully with you.

I would even add to it that the more development and more aggressive development of renewable wind power, together with pump storage facilities, is I think a marriage made in heaven. You are talking about wind that blows at the time that you don't need, and it doesn't blow when you need it, and you are talking about major regulation issues. If we can marry the two whenever possible it will increase the value of wind from a capacity point of view. So whenever it is possible and whenever within reason the cost is justified this is a technology that definitely should be on the map.

Mr. ISSA. Thank you.

Any of the other ISOs?

Mr. LYNCH. We do have pump storage in New York, and it works pretty much off of our locational pricing, and it is compensated as such. I am not familiar enough with the hydrology or the physical terrain around where we have the run-of-the-river hydros and whether we can actually facilitate that, but it is something we can look at. As FERC basically crafts the rules, we would respond accordingly; and I think the market would, also.

Mr. BRANDIEN. We have about 1,600 megawatts of pump storage in New England, and from an operating perspective they're great. When you look at trying to develop resources like wind, where potentially the output of those units can be going up and down significantly, integrating them into the grid, marrying them up exactly like it was said with a quick moving hydro unit makes a lot of sense.

Ms. CURRIE. I think the only thing I would add is, if you have the opportunity to develop such a project close to the load center, that really is an additional advantage.

Mr. ISSA. Pasadena mountains come to mind?

Ms. CURRIE. We're working on it, but I think that is going to be a challenge.

Mr. ISSA. Obviously, these are challenges that remain.

I have one closing question, other than the ones that I would like to submit for the record and ask you to answer at your reasonable leisure. We are going to keep the record open for 7 legislative days so we will submit additional questions.

But I do have one that is a technology question. The conventional load shedding historically has been to go to large users and get them to shut down, industrial users and so on. The technology obviously exists today to go in and turn off the air conditioners or re—turn up the temperature, for example, on the air conditioners of most homes in each of your areas; and yet that is virtually not distributed at all.

I know, and from what we went through in the California crisis, that at the exact time that we were having huge power outages, had we been able to get every home to turn their temperature up to 78 or 80 degrees—we are talking about homes in many cases that had nobody in them but had been left at a comfortable 72 or 74, whatever the homeowner wanted. Had we been able to ramp that up, we would have shaved far more than enough power to prevent virtually every blackout that occurred in California.

What are your ISOs and public utilities doing to roll out or to encourage or to look at putting in the kind of advanced load shedding that would allow for those kinds of individual homes to participate in their own best interest?

Mr. BRANDIEN. In New England, we have a number of demand-response programs, price-sensitive programs as well as 30-minute response programs that we count on for operating reserve to respond exactly like you said.

We do have a number of people that have responded to that gap RFP I talked about in Connecticut, where they actually do shut down or actually raise the temperature or cycle air conditioner compressors. And I believe it is somewhere around 20 megawatts in Connecticut that is in that 260, 270 megawatt gap RFP. I believe it is an untapped resource that is available out there to us. Especially when you take a look—the summer peak demands are really driven by air conditioning.

Mr. ISSA. Thank you.

Any of the other ISOs? Ms. Currie.

Mr. LYNCH. Well, I can just quickly—we administer the wholesale electric market. Therefore, we're not really involved in the retail side that you are specifically talking about. But I will note that the New York PFC is actively involved in looking at retail programs, especially on the demand side as well as the load-serving entities in the large transmission centers. So there are programs that I think people, as you indicate, recognize the benefit and the capability of these programs to reduce and shape peaks. So there is a lot of effort ongoing, but right now it is outside of our area of influence.

Mr. ISSA. But you either get to calculate that if they implement it or not if they don't.

Mr. LYNCH. Yes, we would be very supportive and provide any studies they would need to substantiate what they have done.

Mr. ISSA. Ms. Currie.

Ms. CURRIE. As a retail provider——

Mr. ISSA. We wondered why you were here. Now we know for sure. It is this question.

Ms. CURRIE. The Southern California Public Power Authority has engaged in an experimental project called the Ice Bear, and we're putting this technology into a number of our service territory installations. Basically, you buildup ice over night; and it can provide the cooling for a facility during the daytime when the peaks are higher. As I said, almost all of the SCPPA members now are putting these installations in commercial facilities; and we are going to be exploring what we can do to roll it out on a residential basis.

Mr. ISSA. Excellent.

Mr. Brandien.

Mr. BRANDIEN. If I can add just one more thing, as we move forward in all the rules that we are implementing like with our forward capacity market, we're developing those such that the demand response can play the same game as the generators, which opens up a revenue stream for people to go out and sign up customers where they can cycle off their air conditioning compressors and things. So we are trying to make the rules such that people can take advantage of that.

Mr. MANSOUR. Mr. Chairman, first of all, the technology exists. Advanced metering and signals to the customers in a lot of ways—it does exist in a lot of ways. What is left is the education of the consumers as to how to use the information, how to interpret the information and how to use it.

All the utilities in California, including of course the municipals, they have major programs on advanced metering and using those kind of signals for the consumers to actually do their part for the benefit of both the consumer and the system. The involvement of the ISO would be there would be a signal at the ISO that we have an issue that would go to the utility, and the utility translates that into the signals to the consumers according to the arrangement.

We are very interested in it because, as I said, really as much as we would try to beef up the infrastructure of transmission, there is a lot of room out there for conservation and demand response.

Mr. ISSA. Thank you, and thank you for closing with Governor Schwarzenegger's No. 1 statement when he meets with you.

With that, I would like to thank all of you for your attendance and your patience through our votes. We will hold the record open, according to my script here, for 2 weeks from this date for those who may want to forward submissions and possible inclusions. I would also ask unanimous consent that all Members be able to submit additional questions to our panel.

With that, we stand adjourned.

[Whereupon, at 4:35 p.m., the subcommittee was adjourned.]

[The prepared statement of Hon. Diane E. Watson and additional information submitted for the hearing record follow:]

Opening Statement
Congresswoman Diane E. Watson
Government Reform Committee
Subcommittee on Energy and Natural Resources
Hearing: "Can the U.S. Electric Grid Take Another Hot Summer"
July 12, 2006

Thank you Mr. Chairman. The purpose of this hearing is to examine the reliability of the nation's electricity system in the upcoming summer and examine the four regional "hot spots" identified by the Federal Energy Regulatory Commission (FERC). Our nation's demand for energy has increased 30% since 1990, and the United States Energy Information Administration (EIA) estimates that the demand will rise another 45% by 2025. The existing electric grid was not designed to deal with large-scale, interstate, bulk power transfers that have resulted from industry restructuring activity and we need to come up with solution so next summer we will have no hot spots.

Reliability in the electricity system is an important issue for my home state of California, as well as the entire United States. Recent supply disruptions have caused increased public attention on the critical nature of reliable energy supplies. Since 2000 there have been brownouts, rolling blackouts, and price spikes in several regions of the country. Power outages and other system disturbances in the Midwest and California have increased over the past few summers. In addition, the largest supply disruption in North American history occurred on August 14, 2003. The power outage affected the states of Ohio, Michigan, Pennsylvania, New York, New Jersey, Connecticut, Vermont, Massachusetts, and Ontario, Canada. Approximately 50 million people were left in the dark.

Mr. Chairman, the current confusion surrounding regulation of electricity has placed the reliability of our electric grid at peril. In 1992, Congress passed the Energy Policy Act (EPACT). This law prompted change toward a market-oriented approach to electricity supply. Since EPACT some states have moved toward deregulation and others have not. American consumers are caught in the squeeze of semi-formulated regulation schemes. In addition, FERC does not have the authority to regulate the reliability of the electrical system. The North American Electric Reliability Council (NERC) was established to create reliability guidelines, but compliance with the guidelines is voluntary.

It is of major concern that recent changes in the U.S. electric industry have made it easier for companies

to manipulate electricity pricing. Californians have suffered outrageous electricity pricing, through no fault of their own, with dishonest market manipulation.

The current regulatory scheme does not address unfair price gouging along with market abuses and manipulations from huge corporations. Twenty-four states, and the District of Columbia, have either enacted legislation or issued regulatory orders to implement retail access. California had the first active retail program. A conservative projection estimates California has lost over $9 billion to market manipulation. Reliability and manipulation are connected. Mandatory and enforceable reliability standards as well anti-manipulation rules are necessary to improve the reliability of the electric power system.

Mr. Chairman, I want to commend you again on this timely hearing. It is critical that we investigate the reliability of the electric grid and report back to our constituencies. We want to assure them that the summer of 2006 is not one where they will not be victims of electricity shortages. Demand-side management, standard market design, and enforceable reliability standards are options up for consideration. Congress must focus on giving our constituents reliable service at fair market prices. I look forward to this informational session with FERC, the Independent System Operators (ISO), and Ms. Phyllis Currie, who is on of my constituents and a leader in municipal power in California.

I yield back.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

September 8, 2006

OFFICE OF THE CHAIRMAN

The Honorable Darrell E. Issa
Chairman
Subcommittee on Energy and Resources
Committee on Government Reform
U.S. House of Representatives
Washington, DC 20515-6143

Dear Mr. Chairman:

Please find enclosed my responses to your questions for the record of your Committee's July 12, 2006 hearing entitled "Can the U.S. Grid Take Another Hot Summer?". I appreciate having this opportunity to address your concerns.

If you have further questions or need additional information, I hope you will not hesitate to get back in touch with me.

Sincerely,

Joseph T. Kelliher
Chairman

Enclosure

cc: The Honorable Diane E. Watson
Ranking Member

Responses to Questions for the Record from Chairman Darrell Issa

Q. In your testimony, you briefly talked about the failure of the two transmission lines in upstate New York into New York City. Please provide more information on the details of what caused the failures, when available.

A. Consolidated Edison experienced actually three 345 cable failures within a one-week period in June of this year; the Dunwoodie–Rainey cable (M72), the Sprainbrook-West 49th Street cable (M51), and the Linden to Goethals line (A line). The problem with the A line was quickly isolated and the line restored to service within 24 hours. Feeders M72 and M51 took considerably longer to restore, July 25 and July 17, respectively. Subsequently, feeder M51 failed on July 29 and was repaired and restored to service on August 26.

Regarding the June 2006 failure of these two cables, M72 and M51, connecting the New York City (Manhattan) system with the rest of the New York system, the cause is not currently known. A report on the cause for the failure of these cables is not yet available.

The restoration time is largely dependent upon the cause of the outage. In the case of the A line, the problem was an oil leak in a piece of above-ground electrical equipment that was quickly diagnosed and repaired. Feeders M72 and M51 are underground, however, and diagnosis of the problem was complex and time-consuming. The repair effort involved the excavation of city streets while maneuvering around other underground utilities such as water, sewer, natural gas, and telecommunications equipment. Although underground transmission systems are less susceptible to outages from weather conditions (such as lightning, high winds, and so forth), they typically take much longer to diagnose and repair when they are forced from service.

New York City's recent investment in critical generation infrastructure appears to have relieved some reliability concerns. Loss of the two cables reduced the available capacity of the transmission system to import power but not to the point of causing power shortages in New York City. During the period when both cables were out-of-service, New York City had available generation capacity in excess of 80 percent of its required load and reserves and therefore only needed about 2,800 megawatts (MW) of imported power to meet its total requirement of 13,700 MW. The available capacity of the New York City import system without the two cables was 3,500 MW which increased to about 4,200 MW with the early return of one of the cables in July. The import requirements were adequate to maintain the resources needed to serve the load during peak conditions.

Q. The "trouble spots" (the four major geographic areas) identified in your 2004, 2005 and 2006 staff summer energy assessments—what are the minimum steps necessary to take them "off the list" in future years?

A. The minimum steps necessary to assure that these regions have adequate electricity supply are to increase generation within those regions and increase transmission capacity between those regions and neighboring regions, in order to increase import capacity. The Commission has taken steps in both areas. For example, we have approved market rules to encourage increase electricity supply in New York and New England. We have also issued new transmission pricing rules to encourage greater investment in transmission. Recently, we proposed new transmission siting rules, which supplements the current state siting process. The new siting rules should improve the siting of transmission projects in highly congested areas identified in the recent Department of Energy grid study.

However, resource adequacy is an area that involves both federal and state jurisdiction. State public utility commissions have a responsibility to assure that state-regulated utilities have adequate electricity supply to meet anticipated demand. One area where states could take greater steps is to encourage state-regulated utilities to enter into long term purchase agreements. Many utilities are reluctant to enter into long term purchase contracts, out of concern regarding regulatory risk of future state disallowances. Most of the electricity supply increases in this country over the past twenty years have been provided by non-utilities, independent power producers. Future electricity supply additions by independent power producers will likely be based on the strength of long term purchase agreements. If utilities remain reluctant to enter into long term contracts, we may not develop the electricity supply we need, or we may do so at a higher cost. I encourage state commissions to reduce this regulatory risk. I also recognize that it is important for the Commission to provide a high level of contract certainty.

There has been some progress in these regions. In Southwest Connecticut, current plans indicate that transmission improvements, expected by 2009, will allow for additional imports while improvements to transmission capacity within the region is anticipated to be completed by the end of the year. There have been sizeable generation additions in New York City. A transmission project is being constructed that will interconnect Long Island with New Jersey, offering a new source of supply for Long Island. Although efforts have improved transmission somewhat into Southern California, the area of greatest concern in the state, generation additions have not kept pace with load growth and generation retirements.

Q. How does the growth of renewable energy such as wind, particularly in California, make it more difficult to ensure reliability?

A. During your July 12 hearing, you expressed concerns about the reliability of wind generation to help meet peaks in California. The CAISO recorded its concerns a few years ago when it stated that wind is an "intermittent resource and the level of energy production characteristically declines during hot peak summer days when load is over 40,000 MW" (CAISO, 2004 Summer Assessment, p. 24, April 16, 2004). For 2004, with a little more than 2,500 MW of installed wind generating capacity, CAISO anticipated only 235 MW (or 9 percent of installed capacity) being available under its most likely conditions. This amount was the average measured wind capacity observed when loads were greater than 40,000 MW during the 2003 summer peaks.

California wind capacity has grown to 3,100 MW by this past summer. During July 2006, wind generation reached almost a third of its capacity on one peak day (July 31). Unfortunately, the performance of wind generation was less strong during the three new peak CAISO send-outs recorded during the month. On July 17, wind contributed only 3 percent of its capacity at the new peak. On July 21, wind contributed almost 4 percent and on July 24, wind contributed a little over 8 percent of its capacity. On average from July 17 through 26 – the duration of the heat wave – wind contributed an average of less than 5 percent.

Q. How will the Commission, from a process and timeline basis, get to valuing pump storage in order to define what is advanced transmission and why it can be incorporated at a certain price by ISOs? (The evaluation of the 500 MW Lake Elsinore Advanced Pumped Storage Project, LEAPS, and transmission interconnection).

A. Nevada Hydro Company, Inc., in November 2005 filed with the Commission applications for a license for its pumped storage project and rate treatment for its pumped storage and transmission projects. With regard to the license application, the draft Environmental Impact Statement (EIS) for the Lake Elsinore Advanced Pumped Storage Project (LEAPS) was published February 17, 2006. Following issuance of the draft, Commission staff held public comment meetings on April 4, 2006 in San Juan Capistrano and on April 5, 2006 in Lake Elsinore. The final EIS in scheduled to be issued in October 2006. Before the Commission can issue a license order, it will need the Forest Service's final Federal Power Act section 4(e) conditions (due 60 days after the final EIS), a biological opinion from the U.S. Fish and Wildlife Service (due March 2007), and a water quality certificate from the California State Water Resources Control Board (due March 2007).

With regard to the rate aspects of the project, those matters are currently pending before the Commission. As such, I cannot discuss the disposition or the timing of the case. However, I can offer that under Order No. 672, the Commission's Final Rule on Promoting Transmission Investment through Pricing Reform, the Commission, consistent with section 1241 of EPAct 05, established incentive based rate treatments and decided to provide for incentives for advanced technologies (such as pumped storage) on a case-by-case basis, thereby allowing great latitude for the evolution of technologies and the types of incentives an entity may pursue in support of a particular project. The Commission also decided to rely on existing processes to the extent practicable in determining whether a particular facility is needed to maintain reliability or reduce congestion (the section 1241 criteria) and if an applicant satisfies them, its project will be afforded a rebuttable presumption that it qualifies for transmission incentives. One such rebuttable presumption is for projects that result from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission. It is my understanding that the California ISO has given preliminary interconnection approval to the LEAPS project but has otherwise not completed study of the project. Also, for your information, several entities in California, including Southern California Edison, California ISO, and San Diego Gas and Electric filed comments with the Commission; some comments oppose aspects of the requested rate treatments.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

August 30, 2006

The Honorable Darrell E. Issa
Chairman
Subcommittee on Energy and Resources
Committee on Government Reform
U.S. House of Representatives
Washington DC 20515-6143

Dear Mr. Chairman:

Thank you for your letter of July 31, 2006 including questions for the record of your Committee's recent hearing entitled "Can the U.S. Grid Take Another Hot Summer?"

My responses to the questions from Ranking Member Diane Watson are enclosed. I appreciate having the opportunity to respond to her concerns.

If you have further questions or need additional information, please let me know.

Sincerely,

Joseph T. Kelliher
Joseph T. Kelliher
Chairman

Enclosure

cc: The Honorable Diane E. Watson

Responses to Questions for the Record from Representative Watson

Q. I understand the Senate is moving fairly quickly to confirm three additional Commissioners to the Federal Energy Regulatory Commission (FERC), all of whom bring a strong understanding of the Western electricity markets. Do you know when the Commissioners may be approved, and don't you think it would be prudent to have them on board before FERC acts on the CAISO's Market Redesign and Technology Upgrade (MRTU) proposal.

A. The three additional members have been confirmed and sworn in: Commissioners Philip D. Moeller, Jon Wellinghoff and Marc Spitzer. I look forward to working with them when the Commission considers the MRTU proposal.

Q. I understand that the Locational Marginal Pricing mechanism that CAISO is proposing to implement to encourage more investment in transmission is very controversial in other parts of the country. How much investment in transmission has been made in California over the last few years, compared to the amount that has been invested in markets that have adopted LMP? What about other regions like the Northwest that don't use LMP – have they invested more or less in transmission?

A. The CAISO is proposing to implement congestion management using a system of locational marginal prices. Basically, pricing generation on a local basis allows the prices to reflect the cost of transmission constraints when they occur. The CAISO uses the price information to manage the grid by dispatching generation that helps relieve the constraints and meet load while ensuring a least-cost dispatch. Market participants, like suppliers and load, can use this information in the short term to make a variety of decisions such as: a generator may see an LMP price signal and increase or decrease the amount of generation it is putting into the system or a consumer may decide to reduce its electric use rather than pay higher prices. Market participants also know, at the time they make their decisions, the cost of those decisions. LMP is not the only way to manage congestion. Both PJM and the New England ISO started with other methodologies but transitioned to LMP. If LMP is not used, determining whose power flows over a constraint and whose power does not has to be determined by the system operator on a basis other than least cost. Also, the costs of those decisions, including higher costs resulting from decisions made on other than a least cost basis, are allocated across customers after the fact. The use of an LMP system has the benefit of making prices and, thus, transmission constraints transparent.

While LMP does provide information that could help with investment decisions, use of LMP should not alone determine transmission investment. Investment in new transmission capacity is a long-term proposition, requiring years to design, site and build a facility. The utility or regional transmission entity evaluates the long-term needs of the region, including expected load and generation growth. LMP has been in place in PJM since 1998; New York ISO since 1999; ISO New England since 2003 and the Midwest ISO began using LMP in 2005. Generally available statistics on transmission investment are not that meaningful given the relative newness of LMP and the long lead time for investment. Additionally, the focus of much of the transmission planning (and likely investment) has been on ensuring grid reliability and not necessarily on improvements to the system to remove constraints to allow greater economic trade. However, in response to your question, annual transmission investment as a percentage of total transmission investment has not followed any consistent pattern as can be seen in the below chart. This chart is based upon data submitted annually to FERC by public utilities. This investment includes all investment in transmission, whether for replacement, to hook up new customers, or to add capacity in response to customer requests for service.

Chart 1
Annual Investment in Transmission as a Percentage of Total Transmission Investment

	2001	2002	2003	2004	2005
CAISO	4.25%	5.52%	9.03%	7.63%	7.47%
Pacific Northwest	4.60%	3.04%	3.96%	6.63%	4.08%
NYISO	3.48%	2.63%	1.74%	3.79%	5.07%
PJM	2.14%	1.95%	1.92%	1.94%	3.47%
ISONE	5.33%	5.33%	6.11%	5.53%	8.38%
MISO	11.47%	3.95%	4.11%	4.46%	6.42%

Q. How long have LMP mechanisms been in place in other parts of the country? Is data available that clearly demonstrates the benefits of LMP to consumers?

A. LMP has been used since April 1998. PJM was the first to implement an LMP-based market on April 1, 1998. NYISO followed on December 1, 1999, ISO-NE's on March 1, 2003 and MISO on April 1, 2005. There have been several studies of benefits of electric competition in general, which examine issues such as the benefit of centralized dispatch, increased inter-regional trade, and new investment.

Study sponsors include Cambridge Energy Research Associates, Global Energy Decisions, Energy Security Analysis, Inc., and the New York Public Service Commission, for example. I am not aware of studies that separate the impacts of LMP from other features of a competitive electric market.

Q. I understand 12 Senators from Western states have sent FERC a letter, urging that it go slowly in considering the CAISO MRTU proposal. They seem to think that the MRTU proposal will affect sales and purchases of power throughout the West. Are you aware of these concerns and concerns expressed by Western utilities in comments filed at FERC?

A. I am aware of the concerns expressed by the 12 Senators from Western states in their letter to FERC, and am attaching a copy of my response, dated July 21, 2006. FERC's ex parte rules preclude me from having conversations about the merits of the proceeding, but I can assure you my colleagues and I will carefully weigh all comments and supporting evidence in the record before we make decisions on this issue. I understand the significance of the MRTU to California and the West, and respect the need to have its electric market redesign considered with the utmost care.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF THE CHAIRMAN

July 21, 2006

The Honorable Maria Cantwell
United States Senate
Washington, D.C. 20510

Dear Senator Cantwell:

Thank you for your June 26, 2006 letter in which you request the Commission to thoroughly consider the issues raised in the recent filing by the California Independent System Operator (California ISO) to comprehensively redesign California's wholesale electricity markets.

I assure you that the Commission is not rushing to judgment on this matter. Our review has been careful and deliberate. In March 2002, the Commission began its consideration of the California ISO's first proposal to redesign its electricity market. Subsequently, we have carefully reviewed each successive iteration of the California ISO's proposal. Over the past four and a half years, the Commission has issued more than 20 orders providing guidance on the California ISO's market redesign proposal, and we have also acted on interim measures to provide immediate remedies to market flaws. In addition, the Commission staff has held numerous technical conferences to discuss the various features of the California ISO's market redesign proposal with all the interested parties, while providing the ISO with assistance to craft a comprehensive proposal for California's wholesale electricity markets. Also, the Commission has provided market participants numerous opportunities to comment over the past several years.

On February 9, 2006, the California ISO submitted its filing, which is a proposed electric tariff that reflects the Market Redesign and Technology Upgrade program (MRTU Tariff). The voluminous filing is approximately 8,000 pages long. Given the extensive and complex nature of the filing, the California ISO requested that the Commission extend the usual 21-day comment period to 46 days. The Commission not only granted this request, but later extended the 46-day comment period by an additional two weeks at the request of many parties. While replies to comments are largely prohibited under the Commission's regulations, the Commission allowed all parties to submit reply comments in this case. The Commission twice extended that deadline, resulting in parties having more than five weeks to file reply comments. Numerous parties have submitted comments and/or protests and, altogether, the Commission has received approximately 2,000 pages of reply pleadings.

We note that while the California ISO originally asked the Commission to act on its proposal by June 2006, it later recognized that its request for a Commission order in June "may be highly ambitious due to the scope of the issues raised in this proceeding." The California ISO also acknowledged that the additional time the Commission granted for reply comments would result in a better record in this proceeding. In its most recent request regarding timing, the California ISO asked that the Commission act on the MRTU Tariff by the third quarter of 2006.

I assure you that the Commission fully appreciates the importance of this filing to the Western wholesale electricity market. We are aware of the implications of this proposal to California and other markets in the West, and that changes to the California market affect the entire region. Recognizing the interdependency of markets and infrastructure in California and the West, we have worked steadfastly over the past years to strike the appropriate balance in addressing California's comprehensive market redesign. At this time, the Commission is carefully reviewing the pleadings and the large record in this complex case. However, as this matter is pending before the Commission, it would be premature for me to discuss the merits of this case.

Thank you for your interest in this proceeding. Your letter and this response will be placed in the public file in the ER02-1656 and ER06-615 dockets, which serves to alert the Commission to the concerns of interested individuals and groups. If I can be of further assistance to you on this or any other Commission matter, please do not hesitate to contact me.

Sincerely,

Joseph T. Kelliher
Chairman

United States Senate
WASHINGTON, DC 20510

June 26, 2006

Chairman Joseph Kelliher
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Dear Chairman Kelliher:

We are writing to request that the Federal Energy Regulatory Commission (FERC) not act in haste while considering the California ISO's proposal, called the Market Redesign and Technology Upgrade (MRTU). The potential impact to consumers in California and the entire West of this 5,000+ page filing (Docket No. ER06-615-000) deserves careful examination before FERC decides whether to approve or reject this complex proposal.

We are concerned that FERC thoughtfully consider the impacts not only to California consumers, but to those throughout the West. As you know, the Western grid is integrated and any changes to the California market will have implications throughout the West.

We know that a number of other entities have urged FERC to examine further the potential impacts of MRTU on the western wholesale electricity market. We too ask that the FERC Commissioners proceed cautiously and provide for a thorough vetting of the issues raised by this proposal. It is more important to get this done right than to get it done quickly. Thank you for consideration of our concerns.

Sincerely,

Jon Kyl   Max Baucus

Craig Thomas   John McCain

ER06-615-000

ORIGIN... OFFICE OF EXTERNAL AFFAIRS

July 11, 2006

2006 JUL 12 P 2:57

FEDERAL ENERGY REGULATORY COMMISSION

Chairman Joseph Kelliher
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Update on California ISO Market Design Issues – FERC Docket No. ER06-615-000

Dear Chairman Kelliher:

We are writing in response to the letter sent to you on June 26, 2006 from twelve Western senators regarding the California ISO's Market Redesign and Technology Update (MRTU) proposal. At bottom, the senators urge FERC to carefully examine the potential impact of MRTU to consumers in California and the entire West. The senators request that FERC proceed cautiously, providing for a thorough vetting of the issues raised.

We agree that the California ISO's MRTU proposal should be carefully considered and fully vetted. However, having actively participated for approximately the last 6 years in the development of MRTU with the California ISO and with FERC, we believe that the time has come for FERC to issue a decision on the proposed MRTU tariff. We believe that on balance MRTU represents a significant improvement over the current California ISO market design, including addressing design flaws that FERC has identified. Moreover, the MRTU market design is largely based on other market designs that FERC has approved and that are successfully operating in other parts of the country. Thus, the MRTU design should not be viewed as experimental or unproven.

While the California ISO and its stakeholders may not agree on all the details and while no market design can ever be perfect, MRTU nonetheless offers potential benefits to market participants, especially as they relate to reliability, compared to the current design and has now advanced to the point where the implementation process can begin. Collectively we will be vigilant and are confident that if the ISO, acting either on its own initiative or in response to a stakeholder's concern, identifies an MRTU design element that should be modified or could be improved, the ISO and stakeholders will act in a timely fashion to bring the issue to FERC's attention along with recommended tariff changes.

Thank you for considering our views on this important matter.

Sincerely,

Michael R. Peevey
President
California Public Utilities Commission

Y. Mansour

Yakout Mansour
Chief Executive Officer
California Independent System Operator

Alan J. Fohrer
Chief Executive Officer
Southern California Edison

Fong Wan
Vice President, Energy Procurement
Pacific Gas and Electric Company

TC Farrelly

Terry C. Farrelly
Vice President – Electric & Gas Procurement
San Diego Gas & Electric

Paul J. Allen
Senior Vice President, Corporate Affairs Division
Constellation Energy

Steve Corneli

Steve Corneli
Vice President, Regulatory and Government Affairs
NRG Energy, Inc.

Jerry J. Langdon
Executive Vice President, Public and Regulatory Affairs
Reliant Energy

cc: Western Senators Signing 6/26 Letter to FERC
California Congressional Delegation
David Wetmore

June 26, 2006

Open Letter to Policymakers

Dear Policymaker:

As economists that have both followed and participated in the discussion on restructuring the electricity industry to support competitive wholesale and retail electricity markets, we prepared this letter to provide our views about the value of continued support for the development of competitive markets for electricity.

Among economists, it is almost universally accepted that well functioning competitive electricity markets yield the greatest benefits to consumers in terms of price, investment and innovation especially when regulated alternatives are no longer warranted. And, despite currently high electricity prices in many regions, driven by very high fuel input costs used to generate electricity, we are confident that well structured markets and robust competition are providing substantial benefits to electricity consumers. More importantly, these benefits will increase over time if an effective restructuring process and competitive market implementation program continue to receive support from policymakers. Unfortunately, recent reports have blamed rising electricity prices on industry restructuring. These reports fail to identify the primary cause of today's rising electricity prices --- dramatic increases in fuel costs at a time when retail rate freezes introduced as a transition to competition have come to an end. We are concerned that faulting competitive markets for today's high prices diverts the focus and resolve of policymakers to continue with restructuring and make further improvements in market institutions and design in order to provide consumers with the full benefits of competition.

First, competition and markets are not to blame for recent increases in electricity prices. The current high electricity prices are largely the result of dramatically higher fuel costs. During the period 2000-2005, the price of natural gas increased 375%, and the price of coal increased 30%. These are the two primary fossil fuels used for electricity generation. These increases have been magnified by the end of many retail price freezes that were put in place in many states as part of the transition to competition. Commodity price increases are being felt both in restructured states and in states with vertically integrated utilities. Retail prices have increased more in restructured states than in regulated states in the last year, largely because of their greater use of clean, natural gas-fueled generating capacity, but they increased less in restructured states in the previous few years. While there has been considerable publicity about sharp increases in electricity prices in restructured states such as Maryland and Delaware, where long-term retail rate freezes are expiring, we would point out that, during 2000-2005, regulated rates increased by 47% in Oklahoma and, since 2000, by 43% in Colorado, just to give two examples. No state, regulated or restructured, will ultimately escape the burden of the higher generation fuel prices we are experiencing now.

Second, properly structured, competitive markets shift the risk of bad business and investment decisions away from consumers by having the shareholders of competitive suppliers, and not electricity customers, bear those risks. Cost-of-service regulation clearly has its place in some aspects of the electricity industry such as distribution and transmission. However, where market forces can operate, as they have for electric generation, competition can shield consumers from construction and operating cost overruns. The shifting of risks from customers to suppliers in a competitive market is a huge benefit for consumers in the long run since wiser investment choices and better cost control incentives will lead to more efficient outcomes.

Third, restructured electricity markets are an efficient and reliable way to allocate resources, and there is growing evidence and convincing studies that show that consumers have saved billions of dollars in energy costs as a result of competitive markets when compared to the traditional regulation in effect before competition was implemented. The savings from competition are real dollars in the pockets of consumers, and those savings will continue after fuel prices retreat from their current high levels. In addition, there have been multiple new entrants and large gains in generator performance with competition. One estimate found that performance improvements from divested power plants produced enough additional energy to power more than 25 million households in the Eastern interconnect for a year. Customers are beginning to gain access to more tailored products and services. Credible price signals provide opportunities to develop a robust demand response that both has a significant price dampening effect and relieves the stresses and strains on the delivery systems. And, restructuring and competition have brought significant environmental benefits, with reduced emissions resulting from increased operating efficiencies, improved regional dispatch of generating resources, and the use of market signals to stimulate increased investment in transmission, emission control technology, highly fuel-efficient new generation and renewables.

In sum, despite the recent increases in electricity prices, policymakers should stay the course and continue to support restructuring and the evolution of competitive wholesale and retail markets for power. Competition is the very foundation of our nation's economy. Competitive electricity markets are relatively new and will continue to evolve. We urge policymakers to focus on making necessary improvements in market design and resist the temptation to reject competition for a return to heavy-handed regulation. We are persuaded that competition in electricity markets will stand the test of time and continue to provide visible customer benefits.

Sincerely,

Paul L. Joskow
Professor of Economics and Director of the Center for Energy and Environmental Policy Research
Massachusetts Institute of Technology

Alfred E. Kahn
Robert Julius Thorne Professor of Political Economy, Emeritus
Cornell University

William W. Hogan
Raymond Plank Professor of Global Energy Policy, John F. Kennedy School of Government
Harvard University

Peter Cramton
Professor of Economics
University of Maryland

Howard J. Axelrod
President
Energy Strategies, Inc.

Vernon L. Smith
President
International Foundation for Research in Experimental Economics

David W. DeRamus, Ph.D.
Partner
Bates White, LLC

Gary L. Hunt
President
Global Energy Advisors

ISO new england

Peter Brandien
Vice President, System Operations

August 30, 2006

The Honorable Darrell Issa
Chairman, Subcommittee on Energy and Resources
U. S. House of Representatives
2157 Rayburn House Office Building
Washington, D.C. 20515-6143

Dear Chairman Issa:

Thank you for the opportunity to provide additional testimony on behalf of ISO New England, the Regional Transmission Organization ("RTO") responsible for reliable operation of the bulk power system, administration of a fair and efficient wholesale marketplace for power sales and long-term system planning for the six-state region.

Since the time of the Subcommittee's hearing earlier this year, "Can the U.S. Grid Take Another Hot Summer?" the New England power system successfully withstood two consecutive heat waves with power consumption ultimately soaring to record-breaking levels. For the New England region, power consumption exceeded 28,000 Megawatts on August 2nd, which represents a four percent increase in summer peak demand, or 1,163 MW over last summer. Our regional planning analysis, which spans a ten-year time horizon, forecasts average peak demand growth of approximately 2% each year and average demand growth of 1.5% annually. I mention these events because they are directly relevant to the overall scope of the Subcommittee's investigation and because the challenge of ensuring adequate supply in the face of rapidly growing demand relates to the additional questions asked of ISO New England.

I have provided below responses to the questions received on July 31st.

1. **I understand that ISO-NE's Reliability Must Run (RMR) agreements – which pay certain generators to run in order to maintain system reliability – are controversial in your region and that the ISO itself believes that these agreements disrupt the functioning of "competitive" markets. If this is the case, did the ISO consider other alternatives and specifically, did it consider other "least cost" options before implementing the RMR agreements?**

RMR contracts are a mechanism to keep certain generators available that would otherwise retire or deactivate but are needed to maintain reliable electric service in a certain area. They are designed as a short-term measure to keep a needed facility available by compensating its owner until it is replaced by an alternative market-based resource. Execution of RMR agreements is done with the approval of the ISO's regulator, the Federal Energy Regulatory Commission ("FERC"), and is only allowed after technical study and analysis determines that without the generator reliability would be threatened.

ISO New England Inc
One Sullivan Road, Holyoke, MA 01040-2841
www.iso-ne.com T 413 540 4515 F 413 535 4379

Oftentimes the incumbent utility company and its customers work together with the ISO, state officials and the owner of the needed generator to develop an agreed upon plan for near term reliability of the area, including use of an RMR agreement.

Utilization of RMR agreements was and still is envisioned to be limited to very narrow instances where a generator is needed to provide support to the transmission system or to fill a short term need. However, beginning in 2003, use of and requests for these agreements increased significantly due in large part to an ineffective and outdated capacity market that could no longer meet its intended goal – to provide revenues that could, when combined with other markets, ensure reliable levels of capacity throughout the region. Additionally, the existing market design has not attracted new investment in capacity and virtually no new major developments have come into the region since 2003, yet demand continues to grow at rates mentioned above.

In particular, the number of RMR agreements grew in the import-constrained areas of Southwestern Connecticut ("SWCT") and Northeastern Massachusetts and Boston ("NEMA/Boston"), which include the largest metropolitan areas and the highest concentrations of power demand in New England. As I explained in my oral testimony on July 12th, the ISO has also had to arrange for the purchase of additional capacity during the summer months for SWCT. This includes capacity from emergency generators and customers who can reduce power consumption in response to dispatch instructions from the ISO. For some customers, reducing power consumption is done by devices that can adjust air conditioning settings automatically; others must by actively turn off equipment to reduce consumption. Since the summer capacity deficiency will exist in SWCT until transmission projects are completed, the ISO used a competitive solicitation process known as a Gap Request for Proposals ("RFP") for a four-year period from 2004 through 2007 to get the best price for consumers.

As a general matter, the ISO does not support the use of RMR agreements as the mechanism for ensuring capacity in the region. Rather it is our view that well-designed competitive markets offer the best approach to maintaining and attracting capacity resources at the lowest cost to consumers. Unfortunately, RMR agreements are essentially required in New England today to keep the lights on until an effective capacity market is in place.

ISO New England has made significant efforts over a three-year period to establish a market that can achieve the best near and long-term outcome for consumers in New England and end broader use of RMR agreements to maintain needed capacity. Specifically, the ISO has pursued an improved capacity market structure that will provide for reliable levels of capacity in all locations of the system without having the region's consumers bear the full risk of capacity development or pay for capacity that is not available for use when it is most needed. We believe that a functioning competitive marketplace with these goals and an appropriate set of performance incentives can provide adequate resources at the lowest overall cost to consumers. The New England region is well on its way to having workable markets in place to achieve this outcome.

On June 15, 2006, FERC approved a settlement agreement to implement a Forward Capacity Market ("FCM") for the New England region under which capacity resources will be procured three years in advance of delivery. The forward procurement approach was selected by the region to allow new capacity resources, including demand side resources such as distributed generation, demand reduction and energy efficiency programs, to compete on a level playing field with existing capacity. Since the market will not be in place until 2010, transitional capacity payments will begin on December 1, 2006. These payments will serve to limit the requests and approval of RMR agreements in New England. On October 1, 2006, an improved reserve market will become effective whereby power system reserves are purchased on a forward basis for various locations in New England paving the way for the development of more flexible fast start units to displace the use of older, inflexible and more costly units for this service.

The ISO continues to pursue options to reduce the need for RMR contracts, such as transmission upgrades and enhancements to market rules to encourage more efficient use of power system resources.

2. **I understand that part of the ISO's mission is to ensure system reliability. Does the ISO believe that part of its mission is also to keep costs as low as possible for consumers? If so, what processes or mechanisms does the ISO use to keep costs low?**

ISO New England's overall mission is to operate and plan for a reliable power system and fair and efficient markets. It fulfills this mission as a private, not-for-profit entity independent from the participants in the markets. The ISO has no financial interest in the outcome of the markets. The ISO's decisions about the operation of the power grid and the administration of the markets are based on achieving overall reliability and efficiency.

The wholesale markets are the mechanism the ISO uses to maintain reliability at the lowest cost to consumers. When functioning properly, competitive markets for electricity will deliver power to consumers at the lowest overall cost. Where physical power system infrastructure inadequacies cause prices to be higher in certain locations, the marketplace will reveal the problem and provide a transparent price signal for alternatives to enter the market and possibly reduce prices. Additionally, market pricing serves as a comparison from which to examine the cost-effectiveness of a regulated transmission solution. Incentives built into a competitive market ensure that consumers do not pay the cost of bad investment or poor performance. Prior to the restructuring of its electric industry, New England's consumers were required to pay for the cost of the power system through rates passed on to them by their utilities as approved by state regulators. Under that framework, customers paid the cost of all utility investments, whether good or bad, and without regard for actual performance.

The ISO's regional planning process is another way of keeping consumer costs as low as possible. Each year the ISO conducts a comprehensive, ten-year needs assessment of the power system including how generation, transmission and demand side resources can meet identified needs. It is conducted through an open stakeholder process that includes representation from all participants in the market and assists large consumers and consumer representatives to understand the various alternatives to meeting system needs and the associated costs. For example, consumer representatives may opt to increase spending on targeted efficiency programs and conservation awareness as a way of reducing capacity payments and deferring the timing of new transmission projects. Anticipating and acting on power system needs well before costly reliability problems occur is the best approach to managing power costs. The ISO's regional planning process provides consumers with the information they need to make choices about power system solutions.

3. **How much new transmission has been built in New England over the last five years? What "hammer" does the ISO have to make sure utilities that commit to construct new transmission actually do so?**

The FERC gave ISO New England sole responsibility for system planning in New England in 2000. In 2001, the ISO published its first regional system plan, which identified the need for major transmission projects to ensure the reliability of the bulk power system. Since then, four major new transmission projects have been sited and are under construction in four New England states totaling more than $2 billion in new transmission investment. These projects are needed to reinforce major load pockets and to meet growing demand for electricity in New England. In addition, more than 100 system

Chairman Darrell Issa
August 30, 2006
Page 4 of 4

reinforcement projects have been completed since 2001 totaling nearly half a billion dollars in transmission investment. Prior to 2001, there was a long period in which there was little investment in transmission in the region. The ISO attributes the recent success of transmission progress in the region to its comprehensive regional system planning process and the input of stakeholders.

In February 2005, ISO New England became an RTO, which has enhanced its independence to operate and plan for the power system and develop the wholesale market rules. In this regard, ISO New England has agreements with the region's transmission companies that they will pursue siting of transmission projects identified in the annual regional system plan mentioned above. To be clear, ISO has no authority for transmission siting but to the extent that a transmission project is identified in the annual plan and the utility company does not pursue it the ISO would inform the FERC of the need to move forward with the project. Additionally, the Energy Policy Act of 2005 established federal authority for siting as a backstop to the state siting process in which the federal government can site interstate transmission facilities in a state under certain conditions and after sufficient time as been allowed for state process to address the identified need.

In conclusion, while the New England region successfully managed record demand this summer, we are in need of new capacity resources including power plants and efficiency measures in order to keep pace with forecasted consumer demands for power. With the approval and implementation of improved markets for installed capacity and reserves, New England is well on its way to meet the region's growing need for power. Additionally, the ISO's regional system planning process provides a comprehensive assessment of the bulk power system and reveals the need for system improvements to buyers and sellers of power.

Thank you for the opportunity to testify and provide additional information on the issues.

Sincerely,

Peter Brandien
Vice President, System Operations
ISO New England Inc.

California ISO
Your Link to Power

California Independent
System Operator Corporation

August 10, 2006

Honorable Diane Watson
U.S. House of Representatives
2157 Rayburn House Office Building
Washington, DC 20515-6143

Dear Representative Watson:

By letter dated July 31, 2006, the Honorable Darrell Issa, Chairman, Subcommittee on Energy and Resources requested that I provide to you written answers to certain questions that you were unable to ask at the Subcommittee's July 12, 2006, hearing entitled, "Can the U.S. Grid Take Another Hot Summer." Please find attached the California Independent System Operator Corporation's (CAISO's) responses to your questions.

Thank you for the opportunity to provide this additional information. Please do not hesitate to contact me if you require further information.

Sincerely,

Y. Mansour

Yakout Mansour
President & CEO

cc Honorable Darrell Issa, Chairman, Subcommittee on Energy and Resources

Response of the California Independent System Operator Corporation ("CAISO") to the Honorable Diane Watson

---

Question 1.

I am glad to hear that the public power community, which represents 25-30% of California's electric retail load, is committed to working hand-in-hand with the CAISO to ensure system reliability, and I am pleasantly surprised with the investments these locally-controlled and not-for-profit entities have made in both generation and new transmission. They should be commended. I understand, however, that they are concerned about the market rule changes proposed by the CAISO's MRTU Proposal. One criticism is that your proposed plan does not provide any mechanism to ensure that load-serving entities like Pasadena are able to obtain Long-Term Transmission Rights, as was directed by Congress in the Energy Policy Act of 2005. Can you please comment on why the MRTU plan does not implement these Long Term Transmission Rights?

CAISO Response

The criticism that you cite is not accurate. The CAISO's February 9, 2006 filing of its MRTU proposal with FERC contains provisions for load-serving entities, including municipal utilities like Pasadena as well as investor-owned utilities and direct access retail providers, to obtain one-year transmission rights that can be renewed annually on a high-priority basis that gives these renewals preference over new requests for rights. Although this approach is technically not the same as issuing multi-year transmission rights in a single allocation process, the majority of participants in the CAISO's 2005 stakeholder process on this topic agreed that it was an appropriate approach with which to begin operation of the MRTU markets. The CAISO does not intend these provisions to be the end of the story, however. With regard to the requirements for Long-Term Transmission Rights contained in the Energy Policy Act of 2005, FERC has only recently (on July 20, 2006) issued its Final Rule implementing those requirements. The Rule requires the CAISO to make a compliance filing in January 2007 containing its proposal for implementing Long-Term Transmission Rights, and the CAISO has already initiated activities with its stakeholders toward developing such a proposal. The CAISO intends to comply fully and in a timely manner with the directive of Congress as implemented in FERC's Final Rule.

Further discussion on this topic is contained in the additional information the CAISO submitted to the Committee on July 27, 2006, entitled "Response of the California Independent System Operator Corporation ("CAISO") to the Testimony of Ms. Phyllis Currie, General Manager of Pasadena Water and Power." That additional information is attached for your reference.

Question 2.

A number of entities, including other control areas in the Western Interconnection, have submitted comments expressing concern about the CAISO's proposed market redesign proposal (MRTU), currently pending at FERC. Their concerns focus on how the MRTU plan will be implemented and coordinated with other utilities in the West, especially since they operate under different power scheduling and pricing plans. Don't you think the CAISO and the FERC have an obligation to resolve the specific "seams" issues articulated by the other western utilities before implementing such a dramatic market rule change?

CAISO Response

"Seams" issues will exist whenever there is significant interchange of power between neighboring control areas. Some of the western utilities have seams issues among themselves as a result of differences in their practices and policies, having nothing to do with the CAISO. Some of the more costly seams issues – such as unscheduled "loop" flows – existed before the formation of the CAISO and have nothing to do with MRTU per se. In some respects MRTU even improves upon current seams issues by virtue of its revised hour-ahead scheduling deadline. Of this multitude of different seams issues, it is important for all the neighboring control areas to work together to first establish priorities, and then to develop solutions to those seams issues that are the most problematic and whose resolution offers the biggest payoffs. As noted in response to item 5 of the CAISO's July 12th submittal, the CAISO is committed to working with its stakeholders to prioritize and address seams issues, including the scheduling and pricing of energy transactions at the CAISO's interconnections with its neighbors. That said, the CAISO also has an obligation to the electricity consumers within its control area to address well-known and long-ago identified deficiencies in its current market design. In rulings going back as far as 1999 FERC found that the ISO's current design rules are not aligned with reliable operation of the grid, are not transparent, and result in uplift costs that are spread to all participants. Over the past four years, during which the CAISO worked closely and publicly with all interested stakeholders on the MRTU design, FERC issued a series of orders finding that the CAISO's proposed market design addresses the deficiencies of the current design and represents a major step toward greater price transparency and predictability – both of which we believe were important objectives of the Energy Policy Act of 2005. Therefore, we believe it both appropriate and in the best interest of all consumers in the West to move forward expeditiously and implement the new market design. Notwithstanding that sense of urgency, the CAISO looks forward to working with its neighbors to find mutually acceptable means to address identified seams issues.

Question 3.

If neighboring utilities in the West operate under long-term bilateral contracts (the one utility practice that most market participants agree is essential to prevent a repeat of the 2001 energy debacle) and retain physical rights to transmission instead of the financial rights the MRTU plan proposes, what will approval of MRTU mean to those utilities?

CAISO Response

First, it is important to emphasize that the CAISO's market design proposal will support (and is completely compatible with) bilateral transactions and markets. In contrast to today, however, MRTU will reveal (and price) the true cost of using the "transmission" grid to complete the bilateral transaction, i.e., the cost of congestion and losses. While certain entities have represented that the CAISO's design requires entities to rely on the spot market, this representation is baseless. Consistent with the market designs in place and effective in the Eastern markets, the CAISO's proposed design allows any and all participants to conduct bilateral transactions and, only to the extent they choose to do so, participate in the CAISO's spot markets. This flexibility offered by the MRTU design will in fact enable suppliers of bilateral contracts to meet their contractual obligations more efficiently than they can today by relying on the CAISO market when it is less expensive than running their own power plants, which will make the costs of bilateral contracts more competitive.

As to the nature of the transmission rights needed to deliver power under a bilateral transaction, neighboring utilities that possess "physical" rights outside of the CAISO system will continue to be able to exercise and use those rights as they do today. Moreover, to the extent certain parties have either transmission ownership rights or existing transmission contract rights on the CAISO system, under the CAISO's design proposal they will be able to continue to exercise those rights with no adverse scheduling or financial impact.

As noted above and in the attached material, to the extent an entity wishes to procure the financial transmission rights necessary to hedge their congestion cost exposure associated with a bilateral transaction that utilizes the CAISO grid, the entity can obtain such rights through the CAISO's CRR allocation process if it is a load-serving entity, or purchase such rights through the CAISO's residual CRR auction, or through the secondary market. Moreover, if multi-year rights are needed, the CAISO's proposed "grandfathering" provisions of the CRR allocation rules provide a high degree of certainty that the allocated rights can be renewed from one year to the next. Finally, as explained above, the CAISO is already initiating a stakeholder process to determine if refinements to its CRR allocation rules or other instruments are necessary to comply with FERC's new rule regarding Long Term Transmission Rights. (See FERC's Final Rule *Long-term Firm Transmission Rights in Organized Electricity Markets,* 116 ¶ 61,077 (2006), http://www.ferc.gov/whats-new/comm-meet/072006/E-2.pdf).

Response of the California Independent System Operator Corporation ("CAISO") to the Testimony of Ms. Phyllis Currie, General Manager of Pasadena Water and Power

---

On July 12th, the U.S. House of Representatives, Committee on Government Reform, Subcommittee on Energy and Resources (Committee) held a hearing the focus of which was on the reliability of the electric system across the country. As expressed by Chairman Darrell Issa in his opening statement, the purpose of the hearing was to discuss what is being done to address this summer's challenges identified in the Federal Energy Regulatory Commission's ("FERC") May 18, 2006 Summer Energy Market Assessment ("FERC Summer Assessment"), in which three areas of country were identified as likely to be tight on capacity this summer. The FERC Summer Assessment identified Southern California, Southwestern Connecticut and New York City/Long Island as potential areas of concern. Among those invited to testify at the hearing was Ms. Phyllis Currie, General Manager of Pasadena Water and Power. The focus of Ms. Currie's testimony was on the CAISO's Market Redesign and Technology Upgrade ("MRTU") program, asserting that the CAISO's proposed market design is too complex, will not attract investment nor promote efficient use of supply resources in the western region, and does not offer sufficient financial hedging from congestion costs.

Because there was not an opportunity to discuss her comments at the hearing, the CAISO herein requests to supplement the written record so as to address the issues and concerns raised by Ms. Currie.

For ease of reference, the CAISO provides below summaries and excerpts of Ms. Currie's testimony and then provides the CAISO's response to the cited concerns.

1. *Investors need clear, simple, stable market rules and MRTU will not meet these requirements as it will discourage new investment in generation and transmission and also inhibit efficient use of resources in California and the west.*

CAISO Response.

The CAISO is not breaking new ground in wholesale electricity markets. The CAISO's MRTU proposal is based on well-established and well-founded market designs in place and effective in the PJM Interconnection, the New York ISO, ISO New England, and the Midwest ISO. Indeed, since the CAISO's market redesign effort began in January 2002, the CAISO has heeded the urgings of its stakeholders and regulator not to "reinvent the wheel" and once again create a market design unique to California. The market design that the CAISO put forth to FERC on February 9, 2006, in fact reflects the many lessons learned and the applied "best practices" of the established Eastern markets mentioned above. Ms. Currie is correct that investors need clear, simple and stable rules, and the CAISO's MRTU proposal satisfies those criteria.

FERC has already found it appropriate for the CAISO to move towards a locational marginal price ("LMP") based congestion management system, which is the core of the MRTU design, and has supported the CAISO's move towards such markets. *California Indep. Sys. Operator, Corp.*, 105 FERC ¶ 61,140 (2003) (http://www.caiso.com/docs/2003/10/28/200310281401132393.pdf). The experience from the Eastern markets and our own years of operation have shown us that in addition to clear, simple and stable rules, investors as well as buyers and sellers need market rules that are transparent; in particular, rules for determining market prices that are based on cost causation. In a physical power system this means that prices should reflect the impacts of grid users' energy production and consumption on the grid. MRTU is explicitly designed to achieve this via the LMP approach. In contrast, today's pricing is neither transparent nor based on cost causation. Today significant impacts on the grid due to congestion and losses are spread over all grid users as "uplift" costs unrelated to cost causation. Over the past few years these uplifts have proven to be substantial and largely unanticipated – for example, the cases of intra-zonal congestion in the Mexico border area, and the Minimum Load Cost Compensation (MLCC) related to must-offer obligations. Because the existing market rules and market software prevented the CAISO from allocating these substantial costs based accurately on cost causation, these uplift costs were hotly contested. Moreover, in contrast to costs that are internalized in market prices, such uplift charges are impossible for participants to hedge, thus creating a degree of uncertainty that ultimately drives up prices to end-users. The MRTU design fixes the flaws that made such cases possible, and therefore will contribute to overall stability of the CAISO market rules. Surely, the stability and certainty that Ms. Currie seeks is not represented by continuing with the current design.

It is important to realize, however, that the primary source of incentives for investment in generation will be the state's resource adequacy requirements for jurisdictional load-serving entities. The CAISO's market design must facilitate and support these rules, but securing adequate investment in generating facilities is primarily the duty of state and local regulatory authorities. The CAISO has consistently represented that the MRTU proposal is designed to be supportive of and complementary to the new state resource adequacy programs, but cannot be expected to be sufficient by itself to ensure new investment. That said, the CAISO does believe that the MRTU design will help facilitate generation and transmission investment in the most effective locations by providing valuable price information that will inform investment decisions. By reflecting the costs of congestion and transmission losses at each grid location, the prices calculated under LMP will provide clear guidance for investors considering where to locate new generation, because these prices will reveal how deliveries from alternative potential siting locations will impact the grid, which will in turn enable investors to estimate the revenue streams they can expect to earn by siting at each location.

The same MRTU design principles that help inform investment location decisions also support the efficient use of supply resources to serve customers on a day-to-day basis. The LMP approach determines prices that are consistent with physical power flows and flow limits on the grid and thus provides operating incentives to generators that are fully consistent with operating needs of the grid. Paying supply resources based on energy prices that reflect transmission congestion and losses will promote the most efficient use of resources because such prices compensate generators for operating in a manner that best meets the operating needs of the grid, minimizing the need for costly, non-transparent and unpredictable out-of-market re-dispatch. Moreover, the new Day Ahead energy market that will be created under MRTU will help facilitate and reduce the cost of bilateral energy contracts by allowing suppliers to deliver the contracted energy in a least cost manner, for example, by running their own generation when spot prices are high and buying from the market when prices are low. Such flexibility on the supply side benefits customers by stimulating a more efficient and competitive market for bilateral energy contracts. In recent attempts to distract FERC's efforts toward evaluating and ruling on the CAISO's proposed MRTU market design, some parties have advocated retaining rules similar to today's zonal pricing. Such parties have to date failed to demonstrate how a pricing scheme that ignores congestion and losses can promote operating efficiency and the transparent energy pricing needed to spur investment.

The CAISO would acknowledge that MRTU is not simple, but necessarily reflects the complexities of managing a dynamic electric power grid. As noted above, the design is consistent with other ISO market designs in the US, and therefore is a familiar design to most potential investors. Moreover, the simplicity of the zonal market rules that some parties advocate retaining is illusory – the appearance of simplicity conceals the fact that prices are de-coupled from cost causation, requiring substantial and unpredictable uplift costs that must be spread to grid users on top of the market prices. Any arguments to require the CAISO to retain such antiquated pricing schemes should be considered with caution as such attempts are motivated by a desire to hold on to a congestion management system that obscures the true cost of doing business on the interconnected grid in the West.

2. *The MRTU proposal currently includes general provisions for Congestion Revenue Rights ("CRRs") that have the intended purpose of providing a financial hedge for load serving entities ("LSEs") against congestion costs. Unfortunately, the MRTU CRR proposal in its current state provides no assurance that CRRs will provide an effective hedge against the expanded price risk faced by LSEs.*

CAISO Response.

Ever since the inception of the MRTU proposal in 2002 the CAISO has proposed that Congestion Revenue Rights ("CRRs") be allocated to those that pay for the cost of building the transmission system. On this basis, the CAISO has always advocated that all customers within the system (as represented by the applicable LSE) be allocated CRRs commensurate with their anticipated use of the system. The CAISO reasoned that such an approach is not only fair and equitable, but also is based on the successful deployment and allocation of financial transmission rights in other successful markets, most notably that administered by the PJM Interconnection. Under this approach, Pasadena and any other LSE would receive an allocated share of the available CRRs based on their use of the system to serve their customers. The intent of this approach is to ensure that LSEs – as agents for their end-use customers – receive CRRs sufficient to substantially hedge themselves from potential congestion costs.

In accordance with the CAISO's plan for implementing CRRs, which has been a matter of public record since the 2005 stakeholder process on CRRs, the CAISO is already underway to conduct a complete "dry run" of the proposed CRR rules during 2006. If the dry run indicates a need to refine the CRR allocation rules to improve their effectiveness, such rules will be modified in a FERC filing early in 2007 so that the rules (and resulting allocation) can be modified prior to MRTU implementation. It is also important to recognize, however, that congestion is a real cost in power systems where transmission limits into high-demand areas require the operation of higher-cost power plants inside those areas, and no system of CRRs can eliminate the impacts of such transmission limits. The CAISO is not ignoring such issues, and is working towards addressing such concerns through its transmission planning process, which is extensively coordinated with its Participating Transmission Owners and all stakeholders.

3. *The FERC previously required the CAISO to provide actual CRR allocations to market participants simultaneous with the filing of the MRTU Tariff. The CAISO has not complied with that directive. The CRR provisions in the MRTU Tariff provide merely a theoretical framework that does not allow LSEs to evaluate in any concrete way the likely impact of the MRTU market design on their procurement plans and costs.*

CAISO Response.

Regarding the FERC requirement, the CAISO did in fact provide a thorough and detailed report to FERC on the availability and effectiveness of CRRs five months prior to filing the MRTU Tariff (referred to as the CRR Study 2 Report, filed in September 2005, (http://www.caiso.com/docs/2005/10/04/2005100411302227896.pdf). Although this study was not the same as "actual" CRR allocations, the CAISO explained to FERC – and market participants generally agreed – that determining "actual" CRR allocations this far in advance of MRTU market launch would prevent LSEs from obtaining the best fit of CRRs to their actual needs in 2007-8. The CAISO therefore explained that the actual allocations should be made a few months prior to market launch. As noted above, CRR Study 2 of 2005 will be supplemented by a complete, detailed report on the results of the current CRR Dry Run, which will provide an improved estimate of the hedging effectiveness of CRRs around the end of 2006 and will be filed with FERC along with any proposed changes found necessary to fine-tune the CRR allocation rules.

Again with respect to the distribution of CRRs through both allocation and auction processes, the CAISO is not breaking new ground. The CAISO engaged the services of recognized experts who have been involved in the development of financial transmission rights in the Eastern electricity markets. With the assistance of these experts the CAISO conducted an extensive stakeholder process during 2005, through which we discussed in great detail the various options for allocation and auction of CRRs. After much study and consultation with its experts and stakeholders, the CAISO developed a CRR allocation process that again has incorporated the lessons learned in other electricity markets that have already developed similar instruments (also referred to as Financial Transmission Rights) with special regional considerations for California. As expressed in the testimony of Dr. Scott Harvey and Dr. Susan Pope, filed by CAISO with FERC in support of its MRTU filing earlier this year, the CRR allocation methodology reflects the "design choices that the CAISO had to make in striking a balance between the interests of different groups of stakeholders and to avoid unintentionally inequitable allocation outcomes." (http://www.caiso.com/1798/1798f5ff5f980.pdf)

4. *The CRR process as proposed by the CAISO fails to provide any mechanism for long-term transmission rights (LTTRs). Indeed, explicit limitations on the extent of grandfathering for CRRs from year to year make it impossible for LSEs to count on CRRs to hedge long-term resource commitments. FERC issued a draft rule on February 2, 2006 to implement the long-term transmission rights ("LTTR") provisions of EPAct 2005 and we believe it is a good, strong rule that fulfills Congressional intent. However, the CAISO not only has failed to comply with the FERC's previous directives [in reference to a 1997 FERC order addressing long-term rights], but it also has asked the FERC to defer any requirement to provide long-term transmission rights pursuant to the new rule until at least one year after implementation of the MRTU proposal.*

CAISO Response.

Recognizing the need for longer term protection against congestion for load, the CRR design proposal provides a priority for holders of CRRs that were allocated in the allocation process to renew a portion of their holdings from year to year, the so called "grandfathering" noted above. Although this is not the same as issuing multi-year rights all at once, it accomplishes the longer-term hedge for load with a high degree of certainty because such renewable rights are issued before any new CRRs are issued in subsequent years. This grandfathering feature of MRTU significantly improves upon the current Firm Transmission Right ("FTR") design in effect in CAISO, which has no provision for priority renewal of rights. Ms. Currie is concerned that this feature includes a limitation on the quantity of CRRs eligible for priority renewal. Because of the competing interests of its stakeholders, the CAISO has set the limits in the most just and reasonable manner based on the information it has at this time. As indicated above, the CAISO and its stakeholders will have an opportunity to further test the limiting parameter Ms. Currie refers to and will adjust the parameter if it is found to be necessary to expand the priority renewable portions. Finally, the

CAISO notes that FERC's rulemaking on LTTR issued on July 20, 2006 explicitly provides that long-term coverage may be provided through a combination of initial term length of rights plus renewal capability, which is the model the CAISO will have in place at the start of the MRTU markets. (See Guideline Number Four of FERC's Seven Guidelines in its Final Rule *Long-term Firm Transmission Rights in Organized Electricity Markets,* 116 ¶ 61,077 (2006), http://www.ferc.gov/whats-new/comm-meet/072006/E-2.pdf) ("LTTR Final Rule")

CAISO stresses, however, that there is not universal agreement among stakeholders that multi-year rights are desirable immediately upon MRTU market launch. In stakeholder working group discussions there was a widely expressed preference not to issue multi-year rights in the first year of MRTU to allow parties to become familiar with the new market structure. In the CAISO's comments to FERC on the LTTR NOPR we noted the diversity of stakeholder views on multi-year rights and committed to include this topic in our stakeholder discussions to identify high priority enhancements to the CAISO markets subsequent to MRTU market launch. All three California investor-owned utilities and the California Public Utilities Commission filed comments in the LTTR NOPR proceeding in support of the CAISO's proposed approach.[1]

On July 20, 2006, FERC issued its final rule on LTTRs requiring that transmission owners with organized electricity markets file with FERC no later than 180 days from the date on which the final rule is published on the Federal Register either 1) tariff sheets and rate schedules that make available LTTRs that satisfy the seven guidelines set forth in the final rule; or 2) an explanation of how the current tariff and rate schedules

---

[1] The following comments were filed with FERC commenting on the Notice of Proposed Rulemaking proceeding at FERC on LTTRs:

"PG&E supports the CAISO's request, made in Docket No. RM06-8-000, that the Commission allow the CAISO an extension of time to fully comply with the Commission's forthcoming rule to implement long-term transmission rights...and that ...[the] "Priority Renewal Process"... provides some of the functionality intended by the 2005 EPAct and the Commission's proposed rule." Pacific Gas & Electric Company, Motion to Intervene, Comments and Limited Protest, Docket ER06-615-000 (filed April 10, 2006) at pp. 26-27. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10994923

"SCE agrees that eventually the CAISO should put in place long-term transmission rights, but such rights should not be in place on day one of the MRTU implementation. Given the current degree of uncertainty in market structure, SCE agrees with the CAISO comments filed in the Long-term Transmission Rights NOPR in which the CAISO asks for a sufficient amount of time to evaluate the efficacy of the new market design prior to issuing long-term rights." Reply Comments of Southern California Edison Company on California Independent System Operator Corporation's Tariff Filing to Reflect Market Redesign and Technology Upgrade, Docket ER06-615 (filed May 16, 2006) at p. 29. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11028108

"SDG&E urges the Commission to address these compelling concerns by directing the CAISO, in the final NOPR, to adopt an implementation plan for the new guidelines that requires the CAISO to include LT FTRs beginning with the implementation of its planned MRTU Release 2." Reply Comments of San Diego Gas & Electric Company on FERC's Notice of Proposed Rulemaking Concerning Long-Term Firm Transmission Rights in Organized Electricity Markets, Docket RM06-8-000 (filed April 3, 2006) at p. 3. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10990804

"At this time, FERC's imposition of a multi-year firm transmission rights product in the CAISO control area would likely conflict with the CAISO's new market design and delay its implementation. Additionally, such a requirement is unnecessary because the CAISO's CRR product is consistent with the objectives of the Energy Policy Act of 2005 and fulfills many of the NOPR's proposed guidelines for a firm long-term transmission product. Thus, the CPUC believes that California would benefit more from proceeding, without material alteration, to the planned 2007 implementation of MRTU's CRR product, with the potential for expansion of the terms of those rights or development of another multi-year product after MRTU is successfully implemented." Notice of Intervention and Comments of the Public Utilities Commission of the State of California, Docket No. RM06-8-000 (March 13, 2006) at p. 5. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10972917 already provide for such rights. (LTTR Final Rule at P1). The CAISO intends to fully comply with FERC's directives and is currently evaluating the implications of this order on its MRTU design changes timeline.

Through the stakeholder process that the CAISO has already begun and which will continue over the next several months, stakeholders will be provided an opportunity for full consideration of the needs for long-term transmission rights and alternative possible approaches for meeting those needs. The CAISO will ensure that its obligations under the LTTR Final Rule are fulfilled having fully explored all options on LTTRs with its stakeholders. Thus, the absence of explicit long-term rights in the filed MRTU proposal should be viewed as only an initial condition of the MRTU design, and in the meantime the priority renewal provisions of MRTU provide a way to achieve comparable certainty regarding power delivery costs.

It is also worth noting that the diversity of views on the need for LTTR is not peculiar to California and therefore should not be surprising. In its comments on the LTTR NOPR the NYISO described its experiences offering multi-year rights. In year 2000 the NYISO offered two-year and five-year rights, but these offerings were subsequently discontinued due to lack of participant interest in acquiring them. (Comments of the New York Independent System Operator, Inc., Docket RM06-8-000, (filed March 13, 2006) at pp. 8-9. http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=10973453). The CAISO recognizes that California's circumstances may be significantly different to New York's, but the point is that we should not proceed to implement a major new market design element without thorough stakeholder vetting of the underlying needs and the design alternatives. The recent FERC ruling on LTTR appears to grant us the flexibility to conduct such a process and determine the most appropriate design. (LTTR Final Rule PP 17-18)

5. *The MRTU proposal also intensifies on-going concerns with "seams" between the CAISO markets and other markets in the Western region. There have been continuing seams problems between the CAISO and other sub-regions in the West since the CAISO began operations in 1998. Unfortunately, the MRTU proposal does nothing to minimize the seams problems and, in fact, includes features that will make them worse. For example, the MRTU proposal includes a complex series of Day Ahead, Hour-Ahead Scheduling Process ("HASP") and Real Time market processes with scheduling timelines that differ from the prevailing practices. Although the deadline for scheduling in the HASP under MRTU will be closer to the active scheduling hour than the deadline currently in effect under the CAISO's existing market design, it still will be at least forty-five minutes earlier than the prevailing practice in the remainder of the Western Interconnection. This has the effect of discouraging transactions among sub-regions in the West and increasing the prices for transactions that do occur. Indeed, several suppliers in areas outside the CAISO Control Area, including the Bonneville Power Administration, identified features of the MRTU market design that would discourage transactions with entities within the CAISO Control Area.*

CAISO Response.

This critique is misleading. First of all, the time line for the Day-Ahead Market under MRTU does not change from today. While this may be viewed as a failure to improve a current seams problem, the Day-Ahead time line was thoroughly discussed in stakeholder working groups where there were mixed views on changing the Day-Ahead time line, with broad support for maintaining the current closing time. Second, MRTU improves upon current differences between CAISO and the rest of the west, particularly by moving the intra-day scheduling deadline from 2.25 hours before each operating hour (T-135) up to 1.25 hours (T-75) – a change that is noted but dismissed as insignificant in the above critique. This change has been widely sought by parties scheduling interchange transactions, and will facilitate increased intra-day trading of power for import and export to and from the CAISO control area. The CAISO has further committed, in its recently published Market Initiatives Roadmap, to work with stakeholders on a host of seams issues including the ability to schedule energy transactions after the T-75 hourly market closing time.

In other ways, MRTU does depart further from western scheduling practices, but by doing so provides a foundation for a change in practices that several other areas are considering. In particular, MRTU moves from a purely path-specific scheduling approach, which ignores the physical realities of power flows, to a "source-to-sink" or "flow-based" approach that reflects the actual flow of power on the transmission grid. The fact is that such a change has the potential, if more widely adopted in the west, to significantly relieve the chronic problem of unscheduled loop flows in real time, which are a challenge to reliable operations as well as yet another non-transparent cost that is spread to all grid users.[2] Thus the CAISO's MRTU proposal, though stepping out ahead of many of our neighbors, is a major step toward greater price transparency and predictability. For this reason, some other control areas in the west are considering moving to a flow-based scheduling approach. The CAISO looks forward to working with its neighbors to address unscheduled flows and other seams issues that are problematic features of archaic scheduling practices.

6. *In addition, limitations in the settlements and bidding processes included in the MRTU proposal will both restrict and increase the risks associated with transactions between LSEs within the CAISO Control Area and potential buyers and sellers in other sub-regions of the West. If an LSE in the CAISO Control Area finds that it needs additional resources on an Hour Ahead basis, it will face a significant price risk for importing a resource from outside the Control Area. Under the complex MRTU settlements proposal, the import will be paid the Hour Ahead Locational Marginal Price ("LMP") at the import point, but the LSE arranging for the import will pay a different price for the load to be served by the import.*

CAISO Response.

The example cited is really a complaint about locational pricing, not about limitations in the MRTU bidding and settlements processes. The price difference referred to above is simply the cost of congestion and losses between the point where power is imported into the CAISO grid and the load location. The reference to the Hour Ahead price as a source of additional risk is another red herring. The fact is that imports and exports are priced at hourly prices in the Hour Ahead Scheduling Process rather than in the Real Time Dispatch process, due to the fact that interchange flows between the CAISO and its neighbors must be scheduled on a 60-minute basis, which is consistent with the LSE's load being settled on a 60-minute basis.

7. *These concerns are among those that prompted twelve U.S. Senators to write recently to the Chairman of the FERC, Joe Kelliher, expressing concerns about the CAISO's market redesign proposal and requesting the Commission to "proceed cautiously and provide a thorough vetting of the issues raised," in particular, features such as centralized, bid-based dispatch of generation,*

---

[2] The high-voltage transmission system in the West forms a big loop or "donut" that encompasses the entire West. Regardless of what parties' contracts state or what schedules are made, power flows in accordance with the laws of physics around this loop. The traditional scheduling approaches that are still widely used throughout the West, which Ms. Currie's testimony suggests we should retain for consistency, create a chronic disparity between scheduled and actual power flows, leading to unscheduled "loop flows" in real time that can greatly impact grid operations.

> *locational marginal pricing for supply and financial rights in lieu of physical rights to manage congestion.*

CAISO Response.

This comment misrepresents the Senators' letter by suggesting that the Senators have voiced Ms. Currie's specific concerns. There is no evidence of this. Quite the contrary, the letter urges caution, due diligence and thorough vetting of issues, but does not identify any specific concerns with the CAISO's MRTU proposal and in particular does not recognize any of the specific concerns mentioned by Ms. Currie. (For ease of reference this letter is attached.)

Moreover, it is important to mention that on July 11, 2006, the California Public Utilities Commission, Southern California Edison Company, Pacific Gas and Electric Company, San Diego Gas & Electric Company, NRG Energy, Inc., Constellation Energy, Reliant Energy, and the CAISO sent a response to Chairman Kelliher requesting that FERC act on the CAISO's MRTU proposal, stating that the proposal represents a "significant improvement over the current California ISO market design, including addressing design flaws that FERC has identified." (Attached)

In summary, the CAISO believes that the caution and thorough vetting of issues urged by the western Senators have been provided through the four years of stakeholder meetings, FERC filings by the CAISO and by the stakeholders, FERC-sponsored technical conferences, and FERC guidance orders that preceded the CAISO's February 2006 filing of the MRTU proposal for final FERC approval.